Federal Ministry
for Economic Affairs
and Climate Action

Electricity market design of the future

Options for a secure, affordable and sustainable electricity system

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BMWK	Federal Ministry for Economic Affairs and Climate Action
CfD	Contract for Difference
CO_2	Carbon dioxide
DCM	Decentralised capacity market
EEG	Renewable Energy Sources Act
EnWG	Energy Industry Act
EOM	Energy-only market
GW	Gigawatt
GWh	Gigawatt hour
H_2	Hydrogen
IEA	International Energy Agency
CoCM	Combined capacity market
CEEAG	Guidelines on State aid for climate, environmental protection and energy
CMP	Capacity safeguarding mechanism through peak price hedging
PKNS	Platform Climate-Neutral Electricity System
PPA	Power Purchase Agreement
PV	Photovoltaics
ROSC	Regional Operational Security Coordination
TWh	Terawatt hours
TSO	Transmission system operator
DSO	Distribution system operator
CeCM	Central capacity market

Summary

Aim and background of the present electricity market paper

Germany's electricity system is going through a comprehensive modernisation process and faces a paradigm shift. We are moving from a system with relatively inflexible demand and its associated power generation to a system in which cheap and variable generation of electricity from wind and solar PV will be the main pillar and volume provider in the decarbonised electricity system. The accompanying changes are a paradigm shift and the demands on the electricity system of the future will change fundamentally as a result.

The Platform Climate-Neutral Electricity System (PKNS) was set up by the coalition parties and since 2023 has discussed the demands on the electricity market design of the future in a world with a very high share of renewables. A general report summarises the discussion.

In this paper, the BMWK has condensed the range of opinions into specific options for action with their benefits and drawbacks. In some areas, the intention is to encourage discussion on specific options, while in others, specific recommendations are made.

In the agreement reached by the Federal Government on the power plant strategy in February 2024, the BMWK was tasked with preparing an options paper for the electricity market design of the future based on the PKNS discussion, and is hereby complying with this task.

The key points agreed on by the Federal Government in its Initiative for Growth have been incorporated into this paper. To the extent that the paper goes beyond these points in its description of the problem and presentation of the options available, the paper represents an initial proposal for a discussion within the Federal Government and with the political players, the various stakeholders, the Federal Länder, other European countries and the European Commission, and creates the opportunity for public consultation.

At the same time, the paper provides transparency and a common understanding with regard to the alternative viable options proposed and their respective opportunities and challenges.

Fields of action for the electricity market of tomorrow

The options are broken down into the **four key fields of action**, which have already been discussed with stakeholders in the Platform Climate-Neutral Electricity System. They are as follows:

- the investment framework for renewable energy sources,
- the investment framework for controllable capacities,
- locational signals,
- the flexibilisation of demand.

The electricity market design of the future will have four main functions:

1. **Coordination:** Firstly, the electricity market will continue to have the task of organising the optimum, i.e. most cost-effective, use of the required capacities and the demand side.[1]

2. **Investment framework:** Secondly, the market design will have the function of ensuring there is sufficient certainty for investors to enable the necessary investments in new technologies and capacities to be made.

3. **Geographical balancing:** Thirdly, locational signals as part of the market design will have the role of coordinating supply and demand with the transport capacities of the electricity grid geographically.

4. **Temporal balancing:** The fourth task of the electricity market will be to optimise the timing of supply and demand by increasing flexibility in order to provide the most cost-effective overall system possible and to use flexibility in a way that benefits the system.

Field of action 1: The investment framework for renewable energy sources

The key message of Field of action 1 is that the further ramp-up of renewable energy sources needs a sustainable, reliable and cost-effective investment framework, while at the same time the generation of electricity from renewable energy sources must be gradually further integrated into the market. This is also consistent with the unreserved view of the PKNS stakeholders. In a market environment of transformation, market revenues are associated with too much uncertainty to enable the enormous investments required to be made with sufficient certainty and at the pace required. Furthermore, high volumes of electricity from wind and solar PV are often available on the market at the same time, so that while electricity prices are low, renewables at the same time, however, generate hardly any market revenues.

The sliding market premium is currently safeguarding the expansion of renewables and has made a significant contribution to ensuring that expansion has made rapid progress while costs have come down. It is only authorised under European law, however, until the end of 2026. From then on, a funding system will have to be introduced that includes a repayment instrument ("claw-back") for revenues that exceed the funding requirement. This is provided for in both the new EU Electricity Market Regulation 2024/1747 and the guidelines on State aid for climate, environmental protection and energy. This system change will have to be well prepared. That will be the purpose of the discussion based on this paper. The following are available as alternative options:

- Option 1: Supplementing the current system with a refinancing contribution as a repayment instrument

- Option 2: Introduction of two-way production-based contracts for difference

- Option 3: Introduction of two-way non-production-based contracts for difference

- Option 4: Introduction of capacity payments in conjunction with a non-production-based refinancing contribution.

Non-production-based investment frameworks in particular offer benefits by providing incentives for effective plant deployment and a plant design

1 See Box 9 in Chapter 3.2

that benefits the system. The increasing volume risk is also inherently addressed by non-production-based investment frameworks.

In its Initiative for Growth, the Federal Government has agreed on the following:

> *"... while electricity generation from renewable energy needs to be gradually integrated into the market, the further ramp-up of renewable energy requires a sustainable, reliable and cost-effective investment framework. As coal-fired power generation will be ended, subsidies for renewables will be phased out. In future, the instrument of financial support for investment costs (separate capacity mechanism) is to be used to promote the expansion of new renewable energy sources, particularly to ensure that the effects of price signals are free from distortions. For this purpose, this instrument and others are quickly being tested in a market framework based on the Regulatory Sandboxes Act. At the same time, a continued high rate of expansion of renewable energy needs to be maintained in order to enable the targets set out in the Renewable Energy Sources Act to be achieved and to quickly provide as much affordable electricity as possible. In taking this approach, even greater attention will be paid to cost efficiency and market integration. In this context, the options presented as part of the Platform Climate-Neutral Electricity System will be examined and taken into account in the decisions made. In future, renewables will no longer receive funding support as soon as the electricity market is sufficiently flexible and sufficient storage capacity is available."*

In terms of the decisions made by the Federal Government in its Initiative for Growth to switch the support for renewables to financial support for investment costs (separate capacity mechanism), Option 4 comes closest.

Field of action 2: The investment framework for controllable capacities

Field of action 2 shows that a new flexible technology mix will be necessary to balance and secure the variable electricity generation from wind and solar PV. At the same time, the stakeholders are of the opinion that the current market framework is not sufficient to incentivise investments in this new technology mix to a sufficient extent. In particular, the market revenues in the transformation process are once again too uncertain, and the focus is increasingly on capital-intensive fixed costs rather than on fuel costs, since power plants are operated for a few hours only as back-up systems, for example. In addition to a reliable investment framework for renewable energy sources, therefore, the electricity market design of the future should also include a reliable investment framework for controllable capacities.

For this reason, in its Initiative for Growth at the beginning of July, the Federal Government confirmed its intention to introduce a technology-neutral capacity mechanism that will be operational as of 2028. The options presented in this paper and the subsequent consultation process form the basis for the decision planned by the Federal Government to introduce a capacity mechanism.

The aspects examined in the discussion about the "whether" of a capacity market are now shifting to the "how" of its design. A capacity mechanism that is compatible with the energy transition should support an efficient and secure technology mix of power plants, storage facilities and demand response. It should be based on a competitive approach, open to innovation and adaptable. It should be capable of adapting well to the future developments and uncertainties of the energy transition and technological progress, and in this way provide security of supply in a cost-effective manner.

The following alternative options can be considered:

- Capacity safeguarding mechanism through peak price hedging (CMP), possibly supplemented by a minimum price for hedging products
- Decentralised capacity market (DCM)
- Central capacity market (CeCM)
- Combined capacity market (CoCM), including elements of DCM and CeCM

In the case of the *capacity safeguarding mechanism through peak price hedging* (CMP), suppliers are required to hedge their electricity sales against price peaks. The demand for such hedging products on the market can be met, for example, by operators of controllable capacities, such as power plants or storage facilities. It is based on the new EU hedging obligation, which stipulates that suppliers must hedge the volume of electricity they supply.

In the *decentralised capacity market* (DCM), suppliers are given the responsibility of hedging their electricity supplies with capacities. They have the choice as to whether they prefer to use incentive models to reduce their customers' consumption during peak load periods with little wind and solar PV electricity, in order to maintain their own capacities (self-fulfilment) or alternatively to hedge the remaining electricity demand with purchased capacity certificates to the same extent as their electricity customers contribute to the residual peak load.

This means that DCM and CMP are both based on the principle that is already in place today of upholding balancing group commitments. They tend to be particularly open to technology and innovation and open up a wide range of flexibility options. As a result of the strong incentive to practice load reduction in times of high electricity prices (self-fulfilment), they provide additional incentives to improve flexibility. Both approaches are "breathing" mechanisms that can adapt flexibly to the uncertainties in the development of demand during the transformation process. To this end, they make use of the important "decentralised knowledge" local players have acquired about the development of the system and the development of innovative responses.

In both the DCM and the CMP, the costs (in particular those that go beyond the costs for self-fulfilment) are financed on a competitive basis via an increase in electricity procurement costs.

The drawback of the DCM and CMP is that they offer less investment security for investments that are particularly capital-intensive than a central capacity market, because they do not address the problem of timeline mismatch (up to 15 years refinancing period for investors compared with a maximum of the next three years for liquid products on the market). Both are likely to be accompanied by a corresponding monitoring effort.

In the *central capacity market* (CeCM), a central body determines the demand for controllable capacity and then puts it out to tender by auction. The particular benefit of the CeCM is that it makes it possible to have longer-term contracts for financing controllable capacities, thereby ensuring a very high level of investment security and addressing the problem of timeline mismatch.

However, the CeCM usually has difficulties integrating flexibilities such as e-mobility, heat pumps and innovative solutions, as all participants must be prequalified in advance by the central body and it is a challenging task to classify the large number of flexibility options and prequalify them in terms of their contribution to security of supply. In the event that flexibilities and innovations are not taken into account in the CeCM, their business case would deteriorate, as other controllable capacities would enter the market through the CeCM. The CeCM is less adaptable to future developments and is less able to respond to the problem of load uncertainty than the DCM and CMP. In accordance with the guidelines on State aid for climate, environmental protection and energy, any costs resulting from the tender must be passed on to consumers by means of a surcharge. Furthermore, it is stipulated that high electricity price revenues are to be skimmed off by means of a repayment mechanism ("claw-back").

The BMWK currently favours a combined capacity market (CoCM). A CoCM is a decentralised capacity market combined with a central component for controllable capacities that are particularly capital-intensive with longer refinancing horizons. It combines the benefits of the CeCM and the DCM/CMP, as it is able to address the "new world" in an electricity system characterised by renewable energy sources and flexibility extremely well. On the one hand, in the case of investments that are particularly capital-intensive with long refinancing horizons, for which there is a problem of timeline mismatch, the CoCM provides long-term investment security through centralised tenders with long-term contracts. On the other hand, it provides an optimum way of including flexible consumers, storage systems and innovations, and is therefore an extremely technology-neutral design option. It provides the best way of addressing uncertainties in forecasting future developments and the complex changes that take place "as we move forward" by using the decentralised knowledge of local energy suppliers and responsible parties. The CoCM is mixed-funded, as only the costs of the centralised tendering process are to be financed by a surcharge. The surcharge is significantly reduced as a result of the combined approach compared with the CeCM. The costs in the decentralised segment (in particular those that go beyond self-fulfilment) can in turn, on a competitive basis, lead to an increase in electricity procurement costs.

Field of action 3: Locational signals

Field of action 3 deals with the interaction between the market and the grid in an electricity system of the future with a very high share of renewables. With a rising share of renewable energy sources and an increasing number of flexible electricity consumers, it is becoming increasingly important to determine when and where we generate and consume electricity and how this is intelligently coordinated with the grid.

The key message relating to Field of action 3 is that grid expansion remains the structural solution to distributing wind and solar PV electricity in Germany, but that expanding the grid to the last "kW" is not efficient. Grid expansion and redispatch alone cannot overcome the challenges of the future. Some form of locational signals will have to be added. This was also the key message from the stakeholders in the PKNS, although there are many different views on the "how".

In future, a triad will be needed:

1. A significant acceleration of grid expansion,
2. an efficient and secure redispatch, at least as a short-term and transitional measure,
3. locational signals that incentivise producers, consumers and storage facilities to reduce grid costs, supplemented by active grid-based control options.

The following options for locational signals, which can also be combined with each other, are therefore discussed in this paper:

- Temporally/regionally differentiated grid fees (it should be noted that responsibility for the introduction and structure of grid fees lies with the independent regulatory authority, the Federal Network Agency)

- Regional signals in funding programmes
- Integration of loads in redispatch

The options differ both in terms of their mode of action and target group. Some options primarily affect the investment decision ("regional signals"), for example, while others affect the consumption/dispatch decision ("temporally/regionally differentiated grid fees"). Some options tend to target the consumer side ("demand response in congestion management", "temporally/regionally differentiated grid fees"), while others also address the generation side ("regional signals").

An objective discussion on the electricity market of the future and locational signals is not possible if the opportunities and challenges of reconfiguring the bidding zones are not addressed. This is why the subject was also discussed intensively in the PKNS. This paper presents the benefits and drawbacks in an excursus. Due to the challenges, however, a configuration of the bidding zone is not considered by the BMWK to be an option.

Field of action 4: Flexibility

Flexibility will become the new hallmark of a greenhouse gas-neutral electricity system. This will lead to a paradigm shift. In essence, the idea is that in future flexible consumers on the demand side and – as a back-up – flexible, controllable electricity producers on the supply side will use and compensate for variable generation of electricity from wind and solar PV in an optimised manner. Electric vehicles, heat pumps, electrolysers, storage systems and certain parts of industrial processes in particular will be able to respond quickly to fluctuations in power generation. Ultimately, by shifting demand, price curves will also be smoothed out, so that the market value of renewables will improve. Demand-side flexibility will thus have a fourfold benefit:

1. Everyone will be able to benefit from low electricity prices in times of high wind and solar PV electricity,
2. the competitiveness of the German economy will be increased,
3. security of supply will be guaranteed at a lower cost, and
4. the integration of renewables and controllable appliances will be optimised.

There are currently several obstacles, however, in particular to the integration and use of demand-side flexibility. They prevent market players from leveraging the flexibility potential and making the required investments in more flexibilisation. The paper presents the removal of these obstacles, therefore, as a key measure for a climate-neutral electricity system.

It emphasises three principal fields of action:

- Enable price response – implement time-variable and innovative tariff models,
- adapt the grid fee system to promote flexibility, and
- enable industrial flexibility, in addition to reforming individual grid fees.

It should be noted that the sole responsibility for the introduction and design of grid fees lies with the independent regulatory authority, the Federal Network Agency. As early as 24 July 2024, it initiated a procedure to provide incentives that benefit the system by means of a grid fee designed specifically for industrial customers.

The fields of action mentioned above do not yet represent specific measures, but initially describe only the need for action. For this reason, the

Figure 1: Overview of the fields of action and options

Renewables	Sliding market premium with refinancing contribution	Production-based, two-way contract for difference (w/o market value corridor)	Non-production-based, two-way contract for difference	Capacity payment with non-production-based refinancing contribution
Controllable capacities	Capacity safeguarding mechanism through peak price hedging	Decentralised capacity market	Central capacity market	Combined capacity market
Locational signals	Temporally/regionally differentiated grid fees	Regional signals in funding programmes	Demand response in congestion management	
Flexibility	Enable price response – implement dynamic and innovative tariff models	Adapt grid fee system to promote flexibility	Enable industrial flexibility and reform individual grid fees	

BMWK proposes the development of a coordinated **Flexibility Agenda** designed to tackle the further reduction of obstacles to flexibility in a structured manner.

Interrelationships between the four fields of action

For further discussion on the fields of action and any political decisions taken, it should be noted that there are many varied and complex interrelationships between the fields of action. Flexibility and locational signals in particular interact strongly with each other and with the other fields of action. Locational signals for both renewable energy sources and controllable capacities will thus lead to the choice of location for any new investments being made in a way that benefits the system as much as possible and can help to reduce redispatch costs. Locational signals will also ensure that flexibility options are used in ways that are consistent with the current grid situation.

The removal of obstacles to flexibility is a cross-sectoral task – without flexibilisation, other market design options will be much more expensive. Removing the obstacles will result, on the one hand, in renewables being reasonably used instead of being limited, and their market revenues will improve. On the other hand, flexibility avoids inefficient “overriding” in the capacity mechanism. Conversely, not including flexibility in the capacity mechanism would lead to their business case deteriorating, as other capacities would then enter the market.

Finally, the options for the future financing of renewables and controllable capacities are becoming increasingly similar, indicating that a new, common philosophy for a market design will develop, the essence of which will be cost-effective refinancing of fixed costs through the appropriate hedging of investment risks.

Consultation

The BMWK offers interested stakeholders the opportunity to take part in a written consultation relating to this paper until 6 September 2024. Further information can be found in Chapter 5. We plan to present the results of the consultation at a meeting of the Platform Climate-neutral Electricity System after the summer holidays.

The Federal Government will make a decision on the form of the capacity mechanism for controllable capacity (Field of action 2) in the autumn and in the Initiative for Growth has committed itself to adopting the first key points to that effect in October.

1 Introduction

The energy transition as an innovation project that will ensure carbon-neutrality and competitiveness

Germany's electricity system is currently going through a comprehensive modernisation phase. The energy transition and the conversion of electricity generation to renewable energy sources are intended to make the electricity supply in Germany future-proof, climate-neutral and competitive. This will require an almost complete reorganisation of our energy supply and extensive adjustments in all areas of electricity generation, transmission and storage, in addition to electricity consumption. As increasing numbers of sectors will be switching from fossil fuels to renewable electricity in the course of the energy transition, this modernisation process will ultimately affect almost the entire society and economy.

Germany will become climate-neutral by 2045, and earlier in the electricity sector. The International Energy Agency (IEA) recommends decarbonising the electricity sector in industrialised nations by 2035 in order to achieve climate neutrality in all sectors worldwide by 2045 and to allow time for the necessary adjustments in sector coupling and the transformation of national economies.[2] Accordingly, the G7 countries have committed to making their electricity systems predominantly climate-neutral by 2035.[3] In line with this goal, Germany has passed legislation to increase the share of renewable energy sources in electricity consumption from the current level of just over 50 per cent to at least 80 per cent by 2030.[4]

Renewable electricity is becoming the main energy source worldwide, because it has become the most cost-effective option. Renewable energy sources have become the most cost-effective option for generating electricity. The initially high development costs have been paid for and have fallen drastically over the last 15 years. As a result, renewable energy sources are being expanded all over the world, even in areas where there are no climate targets. The European Commission's impact assessment to analyse the most cost-effective way of further decarbonising Europe by 2040 envisages a renewable share of around 75 per cent of total energy consumption, which corresponds to a renewable share of around 90 per cent of the electricity mix – throughout Europe! To this end, investments in renewable energy sources in Europe must reach approx. 1,000 GW by 2030 and this sum will have to be doubled to approx. 2,000 GW by 2040[5]. In Germany alone, we intend to expand 22 GW of solar PV, 10 GW of onshore wind and 4 GW of offshore wind each year and thus contribute to the European energy transition.

The growth in renewable energy sources is lowering wholesale electricity prices and thus strengthening Germany's competitiveness. Wind energy and solar PV systems have no fuel costs and very low variable operating costs. Their electricity can therefore be offered on the wholesale electricity market with marginal costs close to zero, which lowers the wholesale electricity price. This can benefit consumers and industry if the electricity market system of the future points the way, and in particular as soon as the system can respond flexibly. This comes along with higher costs due to the investments required.

2 International Energy Agency (2021)
3 G7 Italy (2024), p. 16
4 See Section 1 (2) EEG
5 European Commission (2024)

The demand for green products is increasing worldwide. As a result, the proportion of renewable energy sources in the electricity mix is increasingly becoming a location factor, a “green seal of quality”, and thus a marketing edge for green products on the global markets. China last year achieved the highest expansion of renewable energy sources in the world.

The electricity system is becoming the driving force behind decarbonisation. The increasing electrification of the transport, industry and heating sectors means that electricity demand in Germany is likely to double by 2045.

The German economy therefore needs large quantities of renewable energy in order to obtain affordable energy for Germany as a strong, competitive and sustainable business location. This is all the more necessary as the EU emissions trading scheme will reduce the supply of CO_2-allowances towards zero by the end of the 2030s, making the use of fossil fuels significantly more expensive.

Germany has already come a long way on the road to transformation:

- Emissions in the energy sector were already down by over 50 per cent by 2023 compared with the 1990 peak. The latest projection by the Federal Environment Agency also shows that the targets for the energy sector will be exceeded significantly by 2030: emissions are currently expected to be over 80 per cent lower than in 1990.[6]

- In 2023, it was possible to cover more than half of Germany’s electricity consumption using renewable energy sources for the first time. Over the past two and a half years, the Federal Government has invested heavily in increasing the pace of expansion and in particular in speeding up the planning and approval procedures for renewable energy sources and the associated grids at European and national level. Newly installed solar PV capacity reached a new record high of 14.6 gigawatts (GW) in 2023. The expansion of wind energy is also gaining momentum again due to wide-ranging regulations designed to speed up the approval procedures for wind power and grids. At 8.8 GW, more offshore wind capacity was successfully applied for in 2023, for example, than is currently in operation in the German North and Baltic Seas. In the case of onshore wind power, the number of newly installed and newly approved plants is also increasing significantly compared with recent years (see Figure 3 in Chapter 3.1.1). In total, we have already built 88 GW of solar PV, 62 GW of onshore and 8.7 GW of offshore wind power.

- At the same time, this has led to a technological development that has drastically reduced the cost of renewable energy sources. In the years around 2010, funding rates of up to 40 ct/kWh drove up EEG-related costs. Today, the majority of newly installed capacity is in the form of photovoltaics and wind energy at less than 10 ct/kWh.

- Grid expansion is also picking up speed as a result of the acceleration measures. In 2023, a total of four times as much grid length was approved as was the case in 2021; this year it will be almost twice as much again. The length of power lines under construction in 2023 was twice as much as in 2021, and this year it will be five times as much as in 2021.

- This has made it possible to phase out nuclear power and also to continue to reduce the generation of electricity from fossil-fueled power plants.

6 Federal Environment Agency (2024)

- A strong increase in renewable energy sources will lead to more hours in which electricity prices on the electricity market are very low, as renewables have no fuel costs. Some consumers can already benefit from this today. As of 2025, all consumers must now be offered so-called dynamic tariffs by their electricity suppliers, allowing them to benefit from the low electricity prices during periods of high wind and sunshine. The smart meter rollout, which is so important for this, was relaunched with the Act to Relaunch the Digitisation of the Energy Transition.

- The hours of very high proportions of renewable energy sources are increasing and leading to greater price differences between the cheap renewable energy hours and other hours, making storage systems and their business models more attractive. At the same time, storage costs have fallen sharply and have recently triggered strong growth momentum. This makes it possible, on the one hand, to make better use of the renewable peaks and "smooth" them out in a more system-compatible way and, on the other hand, to extend the hours of cheap renewable electricity.

- With the implementation of the Power Plant Strategy, the energy transition will make progress in the area of controllable capacity in three ways, in anticipation of a capacity mechanism being introduced. Firstly, the decarbonisation of the power plant fleet will speed up, since we have agreed on a specific hydrogen transition pathway for several power plants. Secondly, the development of new hydrogen power plant technology will be funded and thirdly, the coal phase-out will be secured through the deployment of new power plant capacity.

Market design as an "operating system" for renewable integration. Having succeeded in reducing the costs of renewables significantly in the course of the last few years, ramping up and integrating the market and system is now imperative. This will increase the importance of accelerated grid expansion, while the new, smart electricity market design in particular will play a key role as an "operating system" for the market and for the system integration of renewables. The electricity system is transitioning from inflexible demand and its subsequent generation to a system of flexible demand that follows variable generation. In this system, cheap and variable electricity generation from wind and solar PV are the volume drivers. Storage and a flexible shift in demand from electric cars, for example, electrolysers, heat pumps and certain parts of industrial processes will respond to this, while controllable and flexible power plants will provide back-up. The combination of these options and their intelligent integration are fundamentally changing the demands placed on electricity market design.

Flexibility will be the key to efficiency and low electricity prices. The flexibilisation of the electricity system by means of storage and demand response will be the key to an efficient and intelligent electricity market system of the future. Electricity generation from wind and solar PV will be available in abundance for many hours and lead to very low electricity prices. Even now, electricity prices on the electricity market are frequently around 0 ct/kWh between 11 am and 5 pm. The future electricity market design will ensure that better use can be made of these hours and that companies and households can benefit more from the low electricity prices at times when there is a lot of wind and solar PV, for example, to charge their electric cars. This will also improve the market and system integration of renewables.

The challenges of the energy transition should not be underestimated. The question to be answered is how Germany will manage to lead its economy and industry into a climate-neutral future, while maintaining its competitiveness. The second 50 per cent share of renewables in electricity generation will be more difficult to achieve than the first. Due to the expected increase in electricity consumption, we need a significant increase in the expansion of renewable energy sources. The requirements on grid and system integration will be many times higher, responses to the changes will only come later in some cases, and this will also result in problems and setbacks. This is normal, however, for such major transformation processes. The progress achieved so far, despite all the scepticism and resistance, should inspire confidence, despite the growing challenges.

The energy transition is also a comprehensive innovation project that will contribute to the modernisation of our economy. The consultancy Prognos anticipates a total annual investment requirement of between 15 and 87 billion euros for the energy industry and energy infrastructure by 2045.[7] We are currently in the midst of a major investment drive that will continue for many years to come and focuses in particular on durable and capital-intensive capital goods.

In addition, the integration effort for the high share of renewables and sector coupling will require new technologies, innovative solutions, aggregation models for flexibility, a boost for digitisation and overall a new "system expertise" in order to be effective in bringing together all the many new players in the electricity system. This will create new roles and also new business models, therefore, for market participants and will deliver an innovation boost for Germany at all levels of value creation. "System expertise" will require investment now, but can prove to be a locational advantage and marketing model at a later date.

It is important to cushion the initially higher investment costs. On the plus side of the energy transition are primarily low electricity prices, the elimination of costs for fossil fuels, such as natural gas or crude oil, which would rise in future due to increasing CO_2 pricing, less dependence on imports, investments and a boost to innovation and modernisation. However, these will mean higher investment costs; in particular, the extensive investments in renewable energy sources and grids will have to be financed.

The aim must be to minimise the increase in investment costs through effective solutions and competition and, moreover, to distribute them effectively with the right political decisions. One example is the transfer of the EEG surcharge to the budget, which relieves the burden on consumers and spreads the funding costs across more shoulders. Another example is the amortisation account for the construction of the hydrogen grid. In addition, more demand flexibility can reduce system costs (more stable market revenues for renewable energy, lower prices for consumers). Overall, the specific costs per kilowatt hour generated may even decrease if the increased investment costs of the electricity system are spread over greater electricity consumption (e.g. through heat pumps or e-mobility). A broad scientific consensus from

7 Total climate protection-related investments for a scenario in which the climate targets for 2030 and 2045 are achieved. Energy industry and energy infrastructure includes not only the electricity sector, but also, for example, hydrogen and district heating (Prognos (2024)).

energy system studies shows that an energy system based on renewable energy sources and, in particular, renewable electricity generation is the most cost-effective way forward for a future electricity system that will need to be greenhouse gas-neutral. As long as it's designed right.

The energy transition will only be a success with Europe and is a European project. The energy transition has long been a pan-European project. The "Green Deal" and "Fit for 55 Package" measures adopted in 2022/23 will put Europe on course for decarbonisation and modernisation. Europe has set itself the goal of reducing its emissions by a total of 55 per cent by 2030 compared with 1990. Among other things, the expansion of renewable energy sources is to be increased to 45 per cent of the total European energy consumption. This corresponds to a share of renewable energy sources in European electricity consumption of approx. 60-70 per cent. By 2040, this figure should be around 90 per cent.[8] At the same time, the countries have different conditions and potential (for example wind power on the North and Baltic Seas, hydropower in the Alpine region and Scandinavia, solar PV in southern Europe). This and the increasingly integrated and interlinked internal market will leverage synergy effects and makes it possible to benefit from different weather correlations when generating electricity from wind and solar. Together, the countries bordering the North Sea are tapping into the enormous potential of the North Sea as a "green power hub" for Europe in the "North Sea Energy Cooperation".

At the same time, Europe has a liquid electricity market. This is a key strength of the European internal market. European electricity trading, coordinated by the so-called merit order, ensures that Europe's households and companies can buy electricity from the cheapest kWh available across Europe at any time, i.e. electricity generation to cover overall demand. Liquid electricity trading becomes increasingly important the more renewables enter the system and the steeper the so-called "ramps" become at the market entry and exit of renewable energy sources.

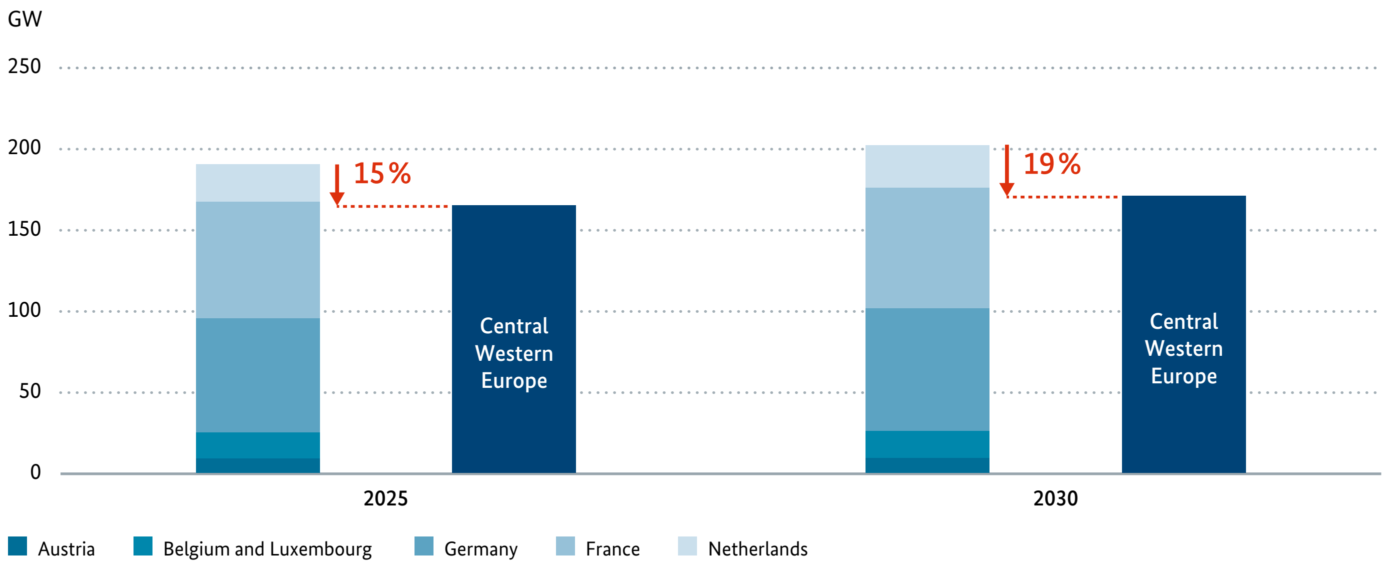
European electricity trading reduces costs, but at the same time also safeguards the security of supply of each Member State. In this way, synergies can be achieved across Europe and a drop in generation in one Member State can be offset by an increase in electricity generation, storage or flexibility in another Member State. As can be seen in Figure 2, the cross-border exchange of electricity will reduce the need for controllable capacities in Belgium, Germany, France, Luxembourg, the Netherlands and Austria alone by 15 per cent in 2025 and by 19 per cent in 2030. This is why the BMWK has been working closely with our neighbours for years within the framework of the "Pentalateral Energy Forum" on issues of regional security of supply and improved electricity trading.

Germany, at the centre of the European internal market, benefits in particular from these synergy effects. On the other hand, this central location also comes with a responsibility for the internal market and European electricity trading. We are therefore also opening up and strengthening our grids for European transit electricity trading.

In order to further increase these positive effects of Europe-wide coordination, further expansion of the electricity grids, both nationally and across borders, is a measure that certainly makes good sense and is also essential.

8 European Commission (2024)

Figure 2: Demand for controllable capacities in Belgium, Germany, France, Luxembourg, the Netherlands and Austria with and without cross-border electricity exchange



Source: Bruegel (2024)

A coordinated Europe-wide expansion of the hydrogen infrastructure and storage can significantly increase European synergies and open up access to the very favourable renewable potential in Spain, for example. Hydrogen can be transported over long distances more efficiently than electricity (capacity of an H_2 line 10-20 GW and a direct current line approx. 2 GW).

A cross-border coordinated European security reserve of controllable capacities for coordinated and harmonised use in unforeseeable crisis situations, as Europe experienced in the 2022 gas crisis, would strengthen synergies in terms of security of supply and additionally secure cross-border electricity exchange, thus strengthening political confidence in the benefits of Europe-wide electricity trading.

Germany has all the prerequisites for a successful energy transition: We have lowered the costs of renewable energy sources and have made considerable progress in terms of their expansion. With extensive acceleration measures, the Federal Government has laid important foundations for the ramp-up of the grids and renewables. Germany also has the economic basis and with 10-20% load shifting, for example, can move large volumes of demand in order to develop efficiencies for the economy and the electricity system. With the prospect of 15 million electric cars on our roads, there is huge potential in market terms for flexible, controllable consumption and storage units to enter the system, in addition to new electrolysers, heat pumps and power-to-heat systems, which we can integrate intelligently, provided the right framework is in place. Germany has a broad network of highly innovative small and medium-sized companies with a wealth of ideas and “inventive skills” that can now be used for the next phase of the energy transition. We have a liquid wholesale electricity market and can benefit from European synergies. It is the task of an intelligent electricity market system of the future to bring all these components together.

Integrative stakeholder process prepares decision

The electricity market design is complex – fundamental decisions will have to be carefully prepared. Already today, the electricity market design is a very complex mechanism with a large number of market players and technologies on the generation, grid operator and demand side: from small, privately operated rooftop solar PV systems to large fossil-fueled power plants owned by large energy companies, from local grid operators to large transmission system operators (TSOs), from large industrial companies with the electricity consumption of a small town to individual households. Then we have the European level, in which the German electricity system is closely integrated, both via the cross-border exchange of electricity with the corresponding need for harmonisation and coordination and via the common legal framework. The mechanisms and interrelationships are complex. Fundamental reforms in Germany have a direct impact on our European neighbours as a result of our central position in the internal market. In addition, security of supply must be guaranteed at all times. A fundamental reform must therefore be carefully prepared so that in future the overall system continues to function reliably and efficiently.

The triad of energy policy objectives will always remain the compass. Even in a future flexible and intelligent electricity system, the electricity supply must be secure, affordable and environmentally friendly at all times. The Federal Government will ensure that it remains so. Citizens and companies alike should be able to obtain electricity reliably at competitive prices at any time of the day or night.

Integrative process: the Platform Climate-Neutral Electricity System (PKNS) has identified key fields of action for the electricity market design with stakeholders. In their coalition agreement, the coalition parties agreed to launch the PKNS together with the SPD, Bündnis 90/Die Grünen and FDP parliamentary groups. Since 2023, in an interactive format, key stakeholders from industry, trade unions, environmental organisations and the Federal Länder have been discussing what adjustments to the electricity market design are necessary to make the electricity market future-proof.

The broad-based stakeholder Platform Climate-Neutral Electricity System has identified and clearly named the need for action in the areas of financing renewable energy sources, financing controllable capacities, locational signals and flexibility. In spite of there being different views on the specific “whether” and “how”, the basis was laid for specifying options for action in more detail at a later date. The following was discussed:

- How can the high and capital-intensive **investments in renewable energy sources** (especially wind and solar PV) be secured in a market environment that is increasingly characterised by very low electricity prices?

- How can the **flexibility potential** be **leveraged** to benefit in the best possible way from the generation of cheap electricity from renewables and reduce back-up requirements?

- How can incentives be provided to ensure that investments in and the use of systems and loads respond to **local situations,** such as renewable energy surpluses or grid bottlenecks?

- How can **investments in controllable capacities** (power plants, storage facilities, demand response) be secured?

With this paper, the BMWK presents options for the electricity market design of the future and provides them for discussion. The paper is based on the previous discussions in the PKNS, which the BMWK has summarised and developed further.

The key points adopted by the Federal Government in the Initiative for Growth have been included. To the extent that it goes beyond the agreements in the Initiative for Growth in describing the problem and presenting options, the paper is an initial proposal for a discussion within the Federal Government and with the political players, the various stakeholders, the Federal Länder, other European countries and the European Commission, and also creates the opportunity for public consultation. At the same time, the paper ensures transparency and a common understanding of the alternative viable options and their respective opportunities and challenges.

Box 1

Platform Climate-Neutral Electricity System

The Platform Climate-Neutral Electricity System (PKNS) provides an essential public discussion forum on future issues of electricity market design. The discussions taking place there has prepared this electricity market paper. Various interest groups from the energy sector, consumer protection, industry and civil society are involved. The relevant Federal ministries and Federal authorities, in addition to the Federal Länder, are also represented. The platform is supplemented and supported by representatives of scientific institutions. A steering group consisting of representatives from the three coalition parties provides support for the process at political level.

The PKNS considers four key topics for the future electricity market design, which are discussed in working groups and plenary sessions: securing the financing of renewable energies, expansion and integration of flexibility options, financing of controllable capacities to cover residual load and locational signals in the electricity markets.

The PKNS has worked out that a form of financing security at low market prices is also necessary for future investments in renewable energy systems in order to safeguard the ambitious expansion pathway of renewable energy sources for a climate-neutral electricity system. The PKNS has identified obstacles in the grid fee system to the flexibilisation of demand and has prepared a roadmap for the ramp-up of dynamic tariffs in order to promote the flexibilisation of the electricity system. It was jointly recognised that a form of locational signals should supplement grid expansion/redispatch. Regionally and temporally differentiated grid fees were discussed as an interesting control instrument and the benefits and drawbacks of reconfiguring the unified bidding zone were emphasised. In addition, key options for securing the financing of controllable capacities to cover residual load were identified: a competitive electricity market, capacity safeguarding mechanism through peak price hedging, a decentralised capacity market and a central capacity market.

With “Use instead of curtail” (NsA), an instrument that was also discussed in the PKNS has already been adopted into law. The regulation in Section 13k of the Energy Industry Act (EnWG) makes it possible to use renewable electricity regionally that would otherwise be limited due to grid bottlenecks.

The discussion in the PKNS has shown that the majority of stakeholders believe that a rapid further development of the electricity market is needed. However, there were very different views on the specific direction this further development should take. The current status of the discussion in the PKNS was published in an integrated final report in April 2024. Overall, the findings of this discussion with the participation of a very broad group of stakeholders form a good basis for the further development of the electricity market design and have been incorporated into this paper.

2 Electricity market of the future

The setting of the electricity system of the future: a significantly altered technology mix and paradigm shift

Wind and photovoltaics will be the volume drivers and most important pillars of decarbonised electricity generation. Onshore and offshore wind generation, in addition to photovoltaics will take over the main part of electricity generation in a decarbonised electricity system, supplemented by hydropower, bioenergy and geothermal energy. The potential of hydropower, geothermal energy and biogenic fuels is limited in Germany. Wind and solar radiation, on the other hand, are definitely available in sufficient quantities to cover the demand for electricity. This will also be the case in many other countries in Europe and worldwide.

Paradigm shift: in future, flexibility will be key to balance supply and demand over time. Weather-dependent, variable electricity generation from wind and solar PV is leading to a paradigm shift: whereas generation used to follow demand, in the decarbonised electricity system, demand is more closely aligned with supply. Large proportions of demand – for example e-mobility, certain parts of industrial processes and electrolysers – will place their consumption in times with a high availability of renewables and consequently low prices. For example, electrolysers in northern Germany will primarily produce large quantities of hydrogen when a wind front leads to high renewable energy generation from wind power. Electric cars will use the midday period when the supply of solar PV is high and cars tend to be stationary anyway at that time. This flexible behaviour also “smooths out” peaks in renewable energy generation and integrates them reliably and efficiently into the market and the system (system benefit). This also opens up new flexibility opportunities for the grid.

Flexibility pays off in several ways: it helps to lower electricity prices and thus strengthens the competitiveness of industry and it reduces system costs by improving grid integration, reducing the need for back-up power plants and also **lowering** the **funding costs for renewable electricity** because it is better used and thus increases its market revenues. In addition, storage and demand response at the right sites and when used in a way that benefits the system support the safe and reliable operation of the electricity grid at both transmission and distribution grid level and reduce the need for back-up power.

A new flexible technology mix ensures security of supply in times of low wind and solar PV:

- **Demand response** such as from heat pumps, certain parts of industrial processes, electrolysers or electric cars can shift the electricity demand to a certain extent and adapt to fluctuating generation from wind and solar PV.

- **Storage systems** tend to compensate for the short-term (hourly to daily) fluctuations in wind and solar PV generation and demand. This applies in particular to pumped storage, large batteries and small battery storage systems in households and electric vehicles. In future, this will be supplemented by hydrogen, which can be stored in underground caverns as largest long-term storage facilities.

- **Controllable back-up power plants**, on the other hand, are the option that can step in when wind and solar PV, in addition to short-term storage and demand response, are not sufficient. They use other, controllable forms of renewable energy (hydropower, geothermal energy, biogenic fuels) or, on a transitional basis, natural gas, but in future hydrogen, which will then be generated ideally using wind and solar PV. The power plants can be used exclusively for electricity generation or for combined heat and power generation (CHP). CHP thus has a dual function, as it not only serves to ensure security of supply in the electricity sector, but can also cover the peak load in a decarbonised heating system, which in future will otherwise be based on heat pumps and other renewable-based heat generation and heat storage systems.

Aim and function of the future electricity market design

The aim of the electricity market design of the future is to bring about and to orchestrate the interplay between wind and solar PV as volume providers and flexible, controllable capacities as back-up. The electricity market design of the future is the operating system that will connect everything. This is the only way to ensure that companies and consumers continue to be supplied with secure and affordable electricity at all times, even in a climate-neutral electricity system.

To this end, the electricity market design of the future has to fulfil four key functions: (1) it must coordinate the use of all capacities effectively, (2) it must ensure that investments in CO_2-free electricity generation are secure, and (3) it must ensure the temporal and (4) geographical balancing of supply and demand.

Coordination function – the electricity market organises the optimum use of the required capacities. The merit order is the supply curve in the electricity market, whereby the final capacity required determines the market-clearing price that is paid to all electricity producers, regardless of their individual marginal costs. If consumers pay this market value, they benefit from the cheapest unit required at that time to cover total demand.[9] In this way, the merit order ultimately ensures that electricity is generated competitively at the lowest possible cost and made available to the market, and that the market does not have to rely solely on electricity generation based on bilateral contracts. At the same time, the merit order also sets the pace for the electricity system, bringing together and effectively coordinating the large number of market players. It therefore has a key information, incentivising and coordinating function in the electricity market, without which the constant balancing of supply and demand could not be guaranteed, or only with significantly higher effort and costs. In addition to economic efficiency, the merit order also ensures security of supply. Only an undistorted price signal enables market players to make the right decisions with regard to the use of their power plants and storage facilities and the temporary reduction of their consumption in times of market shortages.

Taking everything into consideration, the merit order and its functioning were unanimously viewed by the stakeholders in the discussions at the PKNS as an indispensable component of the future market design to efficiently organise the players in the electricity market (coordinating function). Changes or even the elimination of the merit order principle were clearly rejected by the stakeholders.

Market and investment framework – enabling the necessary investments and minimising risks and costs for the economy as a whole. The electricity market design must also provide a reliable investment framework that incentivises and secures the necessary investments and at the same time supports competition. The key task is to allocate the risks in the best possible way and thus minimise costs. In every market, investments are always associated with opportunities and risks. There are risks that market players can cope with well (e.g. weather or price risks), while others in

9 Even in market segments such as intraday trading, where there is no market-clearing price due to continuous trading, or in futures trading with longer-term products, prices are based on the market value. This is because, as a rule, no electricity producer is willing to sell its electricity at a much lower price than its competitors.

extreme cases have a prohibitive effect, i.e. investments are either not made or become very expensive due to risk premiums. The design of the electricity market has a significant influence on how high the risks are and who assumes which risks in optimum fashion – the individual economic players, the consumer community or a central body such as the state. Ultimately, this constitutes a balancing act between economic and political interests.

There were different views in the PKNS as to how the market design should be further developed with regard to the necessary investment security for future capital-intensive investments. There was general agreement, however, on the need for action. The following reasons were identified:

- **Fixed costs will shape the electricity system of the future – fuel costs will become less important.** In economic terms, the costs for fuels and CO_2 (input costs) have frequently had an impact on the conventional electricity system to date, in addition to the fixed costs for maintenance (for investments in new capacities and maintaining existing capacities). This will change in the future. Electricity from wind and solar power does not require any fuel and therefore incurs virtually no input costs; the same will apply as a rule to short-term storage and demand response. Power plants will continue to have fuel costs (later for hydrogen or biogenic fuels) – however, they will only be used as a back-up for a limited number of hours. This means that costs will be predominantly fixed costs – primarily capital expenditure.

- **Different time horizons for capital-intensive investments (timeline mismatch):** the time horizons of investors for particularly capital-intensive investments differ. Wind and solar PV systems as well as power plants are refinanced over longer periods of around 15 to 20 years. However, electricity suppliers generally only protect themselves over shorter time horizons: in the competitive end customer business, they can only commit to procuring electricity into the future to the extent that they are able to sell this electricity to their end customers. This is usually only the case for the next one to three years maximum. In order to obtain the necessary loans for the investment or to limit risk premiums and thus costs, investors (or their banks) need a certain level of revenue security, i.e. a contractual partner who ideally will purchase the electricity over these periods. While some investments have shorter refinancing periods, this timeline mismatch is a challenge for particularly capital-intensive investments. Reconciling these different time periods is known as timeline transformation.

- **High market environment and revenue uncertainty in times of transition:** the energy policy targets provide a clear framework for modernisation. Nevertheless, there is considerable uncertainty for market players during the transition phase as to how electricity consumption will develop in the European internal electricity market, how quickly specific technologies will ramp up (e.g. electric cars, heat pumps and electrolysers), how the technology mix will develop nationally and at European level and, above all, how this will affect the electricity market and thus revenue opportunities. For example, electricity prices on the short-term markets are likely to fluctuate more strongly in future, with the result that hedging against price volatility will become more important. The number of hours in which there are no revenues at all due to very low or even negative prices is also likely to increase. To what extent these effects will have an impact on market revenues, for example from renewables, or on electricity prices for households and companies, will also depend on the pace and the degree of flexibilisation of electricity demand.

- **CO_2 prices alone do not provide sufficient investment security: the** European emissions trading scheme is a trading system for greenhouse gases and limits the amount of CO_2 and greenhouse gases in the participating countries to the quantity for which certificates are available. This has the indirect effect that climate-friendly technologies, for which no certificates have to be purchased, are better able to establish themselves on the market. In the European emissions trading scheme, high CO_2 prices can generally be expected in future, as the absolute quantity of emission certificates is capped and is likely to drop to zero towards the end of the 2030s. In the interests of a socially desirable forecast, prices would have to be made more appropriate for this day and age by market players taking appropriate action and be reflected in sufficiently high investments in renewable electricity generation today. This is not the case, however, a key reason being the uncertainty of future market developments in conjunction with high internal rate of return requirements of investors, since investors cannot be sufficiently certain that the prices required to achieve the target will actually materialise. This influences the calculation of projects, the refinancing horizon of which extends beyond the end of the 2030s. Furthermore, particularly in the case of renewable energy sources, as a result of the so-called **simultaneity effect** (high proportion of renewable energy sources when the sun is shining or the wind is blowing) they are increasingly forcing fossil-fueled electricity producers out of the market. This is, on the one hand, a good thing, but on the other hand, it means that renewables would no longer benefit from the electricity price-increasing effect of high CO_2 prices and would not generate higher market revenues.

- **Lack of confidence:** the confidence of market players in the long-term stability and reliability of the general conditions is a fundamental prerequisite for functioning and competitive markets. In the discussions in the PKNS, it became clear that this confidence had been significantly weakened in the course of overcoming the triple crisis in 2022 – a shortage of natural gas, a prolonged drought with an associated shortage of cooling water in parts of Europe and the temporary shutdown of a number of French nuclear power plants. A lack of confidence is a challenge in terms of the stability of the investment framework. This is all the more important in the case of capital-intensive investment projects with substantial planning and approval lead times.

- **Regulatory uncertainties:** major changes to the investment framework can lead to uncertainty among market players, particularly in the phase between the conception of a reform and its entry into force. Investors need to familiarise themselves with and adapt to the changed conditions. Both of these can take some time. Under certain circumstances, projects may be shelved during this learning and adjustment phase. This wait and see attitude can be reflected in a temporary reluctance to invest and lead to less effective achievement of targets for security of supply and renewable electricity generation, such as a gap in the expansion pathway.

In the view of the stakeholders in the PKNS, all these circumstances combine to make it necessary to safeguard capital-intensive investments through the future market design.

Geographical balancing function – locational signals as an additional component. When and where electricity is generated and produced in future is becoming increasingly important. In the future electricity system, it will increasingly be the case that electricity is no longer generated near the existing load centres, but where favourable generation conditions, such as high wind yield and solar radiation, prevail. This will increase the transport requirements for the electricity grid and requires additional grid expansion, which will significantly increase the transport capacities and thus bring cheap renewable electricity to the consumers and reduce the bottlenecks. The grid operators will resolve any remaining bottlenecks with appropriate measures (known as redispatch).

There was consensus in the PKNS, however, that a form of locational signals is necessary as an additional component for more grid-friendly behaviour on the demand and supply side. In future, the system will balance a large number of decentralised feed-ins and flexible consumers in both geographical and temporal terms, i.e. it will also take greater account of the local situation – in particular the grid situation. Through appropriate intelligent incentives, market players can also adapt themselves more to the grid situation by consuming more electricity locally at times of high local generation of regenerative electricity to relieve the grid. This can be achieved through various forms of locational signals, e.g. through geographically and situationally different price components, such as grid fees or as an element in the investment/hedging framework of other (funding) measures.

Temporal balancing function – providing flexibility and using it for the market and system. In order to enable the paradigm shift towards flexible demand, price signals that are as undistorted as possible must be visible to the various flexibility options. Prices can incentivise and coordinate the use of flexibility options (for example, when electric vehicles can be charged at very low cost) and also intelligently promote behaviour that benefits the system.

Moreover, it is also crucial that the investment framework for investments in batteries or more flexible industrial demand is in place and that new business models can emerge around flexibility. In order for flexibility to become economically viable, current regulations that incentivise in other ways must be examined. The numerous obstacles to flexibility that remain should be systematically removed. Finally, price signals will only be accepted by flexible consumers across the board if the electricity system is able to cope with this coordination task by means of a digital and intelligent metering, communication and control infrastructure.

In the process of reaching a decision on a capacity mechanism, it is crucial to choose a design that takes flexibility into account effectively and does not turn it into a disadvantage.

3 Fields of action and options for the electricity market design of the future

Box 2

European requirements: necessity of repayment-mechanisms ("claw-back") for all variable and controllable capacities

European requirements make a repayment mechanism necessary in the future market design. In response to the 2022 energy price crisis, among other things, the European Commission is now calling for regulations that limit profitability due to unexpectedly high prices. Accordingly, the revised European guidelines on State aid for climate, environmental protection and energy (CEEAG) contain the requirement to avoid any excessive funding in the event of uncertainties about price developments by reclaiming excessively high market revenues (claw-back). This applies to all types of capacities (variable renewable energies as well as controllable capacities) and all types of investment environments, such as two-way contracts for difference (CfDs) or capacity markets.

In addition, the most recent amendment to the EU internal electricity market regulation[10] now also requires Member States to design direct price support schemes to promote certain technologies (e.g. wind, solar PV, hydropower and geothermal energy) after a transitional period of three years as two-way contracts for difference only or equivalent schemes with a repayment mechanism.

It can therefore be stated that state funding without claw-back will in future no longer be possible under European law. It is a question of how this is designed.

The introduction of such repayment schemes is accompanied by opportunities and challenges, which, in some cases, differ depending on the specific technology:

Opportunities

Unexpected additional profits as a result of high price phases will be limited. In principle, a repayment mechanism is a way of counteracting excessive profits as a result of high price phases for power plant operators. This potentially relieves the burden on end consumers and, to a certain extent, offsets the fact that, by hedging investments, the state reduces the risk and thus the costs for power plant operators.

Claw-back clauses favour market investments, at least in the case of renewable energy sources. Power plant operators weigh up economically whether they would rather invest in a public investment environment, within which they would then have to repay excessive market revenues, or outside the public investment environment, which would allow them to avoid such repayments.

→

10 European Union (2024)

Repayment mechanisms can further improve market integration and reduce revenue uncertainty. Depending on the structure of the investment framework, an adequate design of the repayment mechanism can also help to incentivise additional system and market integration. A repayment mechanism can also reduce revenue risks, as the uncertain possibility of corresponding additional electricity market revenues no longer needs to be taken into account in the overall calculation of the investment, if at all. This means that, under certain conditions, a repayment mechanism can reduce the interest on loans or capital costs.

Challenges

An appropriate design of the repayment mechanism is necessary. It is imperative that repayment mechanisms be designed in such a way that efficient market price signals remain undistorted. When designing the mechanism, it will also be important to consider what effects a repayment mechanism will have. This will affect, among other things, the interaction with private hedging transactions, the impact on investors' opportunity costs and interactions in the European internal market due to possibly different types of implementation by the Member States.

For controllable capacities with relevant variable costs (primarily power plants with fuel costs), it must be ensured that the repayment, even in the event that fuel prices fluctuate, only takes effect above the variable costs of the plant. In the event that the repayment was so high that the plant could no longer refinance its fuel costs with the remaining revenues, the plant would no longer have any incentive to produce electricity. This would potentially jeopardise security of supply.

In the case of **storage facilities**, on the other hand, it should be noted that they do not generate their revenues by selling electricity at times of high electricity prices, but through price fluctuations on the wholesale electricity market. A storage facility can therefore generate high revenues even when electricity prices are comparatively low (assuming the electricity was previously purchased at a lower price) or generate low revenues even when electricity prices are high (assuming the electricity was previously purchased at a higher price). A surcharge based on the electricity price level therefore appears less appropriate in such cases.

Demand response does not react solely as a result of high electricity prices either, but primarily in response to short-term price changes on the electricity market. In addition, demand response, strictly speaking, does not ultimately generate revenues as a result of its response to electricity price signals, but reduce its electricity procurement costs instead. A repayment mechanism would ultimately limit the cost savings that result from flexible consumption, which would ultimately run counter to the development of demand response for the electricity system.

3.1 An investment framework for renewable energy sources

3.1.1 Importance of and prospects for renewable energy sources in the climate-neutral electricity system

Electricity from renewable energy sources are the main pillar of the climate-neutral electricity system and the key to competitive electricity prices, especially for industry

Carbon-free electricity generation from renewable energy sources is at the centre of the greenhouse gas-neutral electricity system. The expansion of renewable energies with wind and solar energy at the centre is the main pillar of a secure, affordable and sustainable energy supply in the future greenhouse gas-neutral electricity system.

To ensure that the transition to a climate-neutral electricity system is successful, it is central that the renewable expansion targets will be achieved. Only when there is sufficient electricity from renewable energy plants available it will be possible to meet the demand for electricity and achieve the statutory climate action targets. The Renewable Energy Sources Act defines expansion pathways to 2040, with the interim target of an 80 per cent share of renewable energy sources in gross electricity consumption in 2030. Following the completion of the coal phase-out, the further expansion of renewable energy sources is to be market-driven.

Much has already been achieved: renewables covered over half of electricity consumption for the first time in 2023

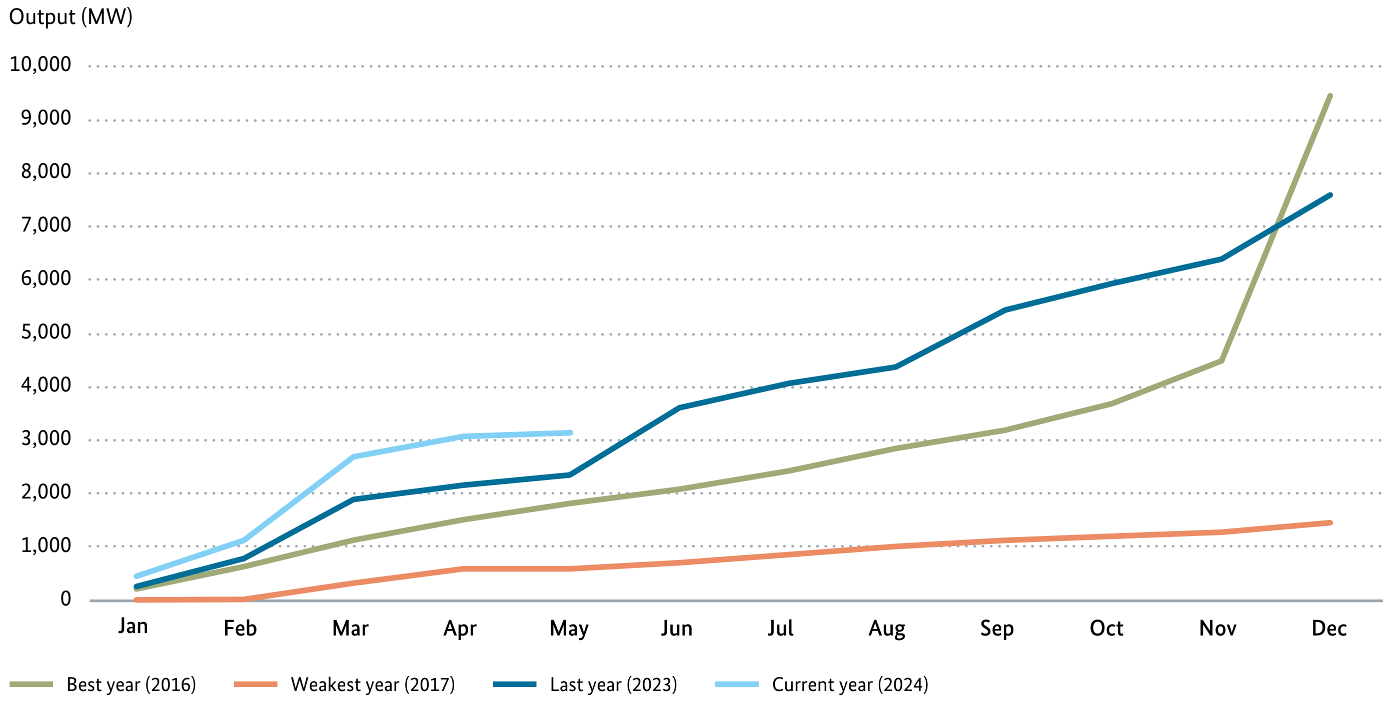
The Federal Government has set the course for achieving the expansion targets. The extensive acceleration during the last two and a half years is having an impact, with the pace of renewable energy expansion picking up significantly and everything pointing in the right direction. This is also the result of the amended acts in the field of renewable energy sources, such as the Renewable Energy Sources Act 2023 and the Offshore Wind Energy Act 2023, in addition to the implementation of the EU emergency regulation to accelerate the expansion of renewable energy sources and grids, the onshore wind strategy, the solar PV strategy and the solar package. These levers are working.

The approval and construction of solar and wind power plants has gained significant momentum:

- The expansion of solar PV systems is on course to achieve a record. With an expansion of 14.6 gigawatts (GW), more solar PV systems were installed in Germany in 2023 than ever before in a single year. This was almost double the number of new solar power plants compared with 2022. When compared with 2021 (5.7 GW), the annual newly installed capacity of solar PV systems has actually increased by more than 150 per cent. The share of solar PV in gross electricity generation in 2023 was thus 12 per cent.

- Onshore wind energy was Germany’s most important source of electricity in 2023: 22 per cent of the electricity generated in Germany came from onshore wind turbines. New plants increased significantly to 3.6 GW in 2023, with almost 50 per cent more plant capacity added than in the previous year, the highest level since 2017. The number of approvals is rising sharply, with over 2.5 GW approved for the first time in the first quarter of 2024 (Figure 3).

Figure 3: Comparison of monthly approved wind energy capacity (cumulated) for 2016, 2017, 2023 and 2024 (the record increase in December 2016 is due to anticipatory effects)

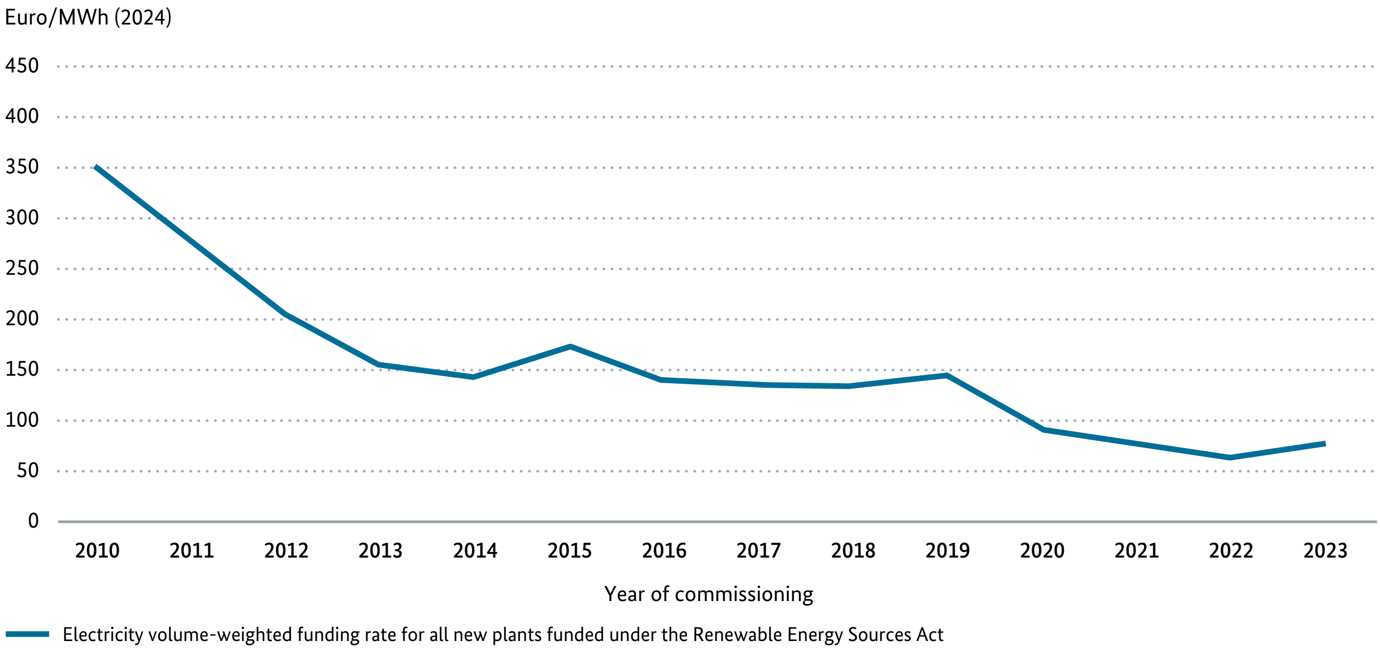


Source: Fachagentur Windenergie an Land (2024)

The funding rates for new plants under the Renewable Energy Sources Act were lower than ever in 2022 and the Federal Government is pulling out all the stops to further reduce costs. In the further expansion of renewable energies, the focus is on the cost-effective technologies of wind energy and photovoltaics. More designated areas, accelerated approval procedures and less red tape mean there is more competition, which has a cost-reducing effect.

As a result, the funding rates for new plants under the Renewable Energy Sources Act are much lower than those for existing plants: Figure 3 shows the average renewable energy funding rates for new plants since 2010. The renewable energy cost burden originates in particular from the years 2009 to 2011. In these years, the expansion of solar PV, among other things, rose sharply, while the funding rates were still very high (up to 40 ct/kWh). In the following years, the funding rates fell and in 2022 were lower than ever before.

Figure 4: Renewable energy funding rates for new plants by year of commissioning

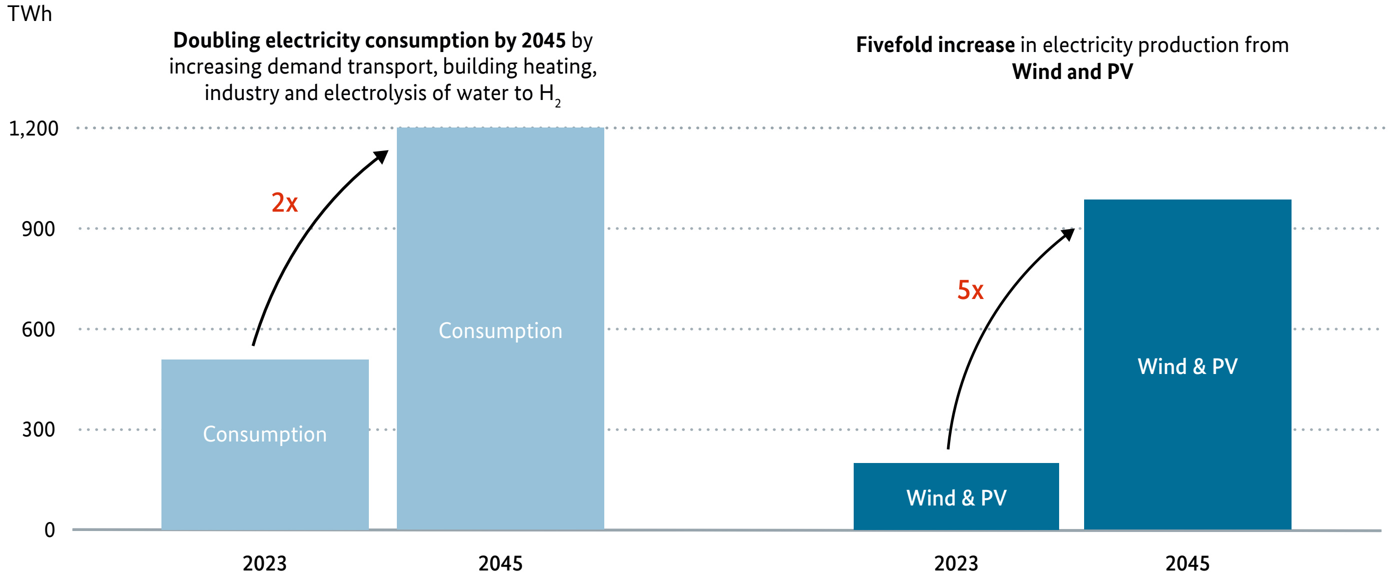


Source: BMWK's own presentation based on data from the project "Direct marketing and other marketing models for renewable energy sources"

By 2045, a five-fold increase in electricity production from wind and solar PV will be required to meet rising demand

It is essential that the positive expansion momentum is maintained, as the largest share of renewable energy expansion still lies ahead of us. By 2045, electricity consumption will be almost twice as high as a result of rising demand in the transport, building heating and industrial sectors, in addition to the demand for electrolysis for the production of hydrogen. To meet this demand, five times as much wind and solar PV electricity will be needed than is the case today (Figure 5). This also corresponds to the renewable energy expansion targets.

Figure 5: Development of electricity consumption and expansion of wind+PV by 2045 with highly electricity-based sector coupling[11]



Source: BMWK long-term scenarios TN electricity. Very similar structure in other scenarios. Simplified diagram.
Graph refers to electricity (TWh): 2023 about 200 TWh wind+PV, 2045 about 1,000 TWh domestic generation.
In terms of capacity (GW), offshore wind requires a factor of 8 (from 8.4 to 70 GW), PV a factor of 5 (from 82 to 400 GW) and onshore wind just under a factor of 3 (from 61 to 160 GW).

The upward trend in renewable energy expansion faces challenges for the future

Uncertain and insufficient electricity market revenues are a major investment risk for capital-intensive investments in renewable energies. In the case of renewable energies, the proportion of initial investment costs compared with total costs is significantly higher than for other electricity generation technologies. Investment costs have risen recently, partly due to rising material, transport and leasing costs. The high investment costs must then be amortised over the lifetime of the plant through revenues. The main source of these ongoing revenues are the electricity market revenues that the plants generate by marketing the electricity produced.

Refinancing through electricity market revenues is also uncertain due to the simultaneity effect. From today's perspective, however, experts generally believe that electricity market revenues alone will not be enough to provide sufficient security to refinance all investments in the renewable energy systems required to modernise the electricity system. The main reason for the low electricity market revenues is the so-called **"simultaneity effect"**. The higher the share of renewables in the electricity system, the more frequently hours occur in which wind energy and solar PV systems feed into the grid at the same time. Due to the marginal costs of renewable energies being close to zero, they can offer electricity very cheaply. This has the positive effect of lowering the wholesale electricity price during these hours, but also reduces the revenues that can be achieved on the electricity market, especially during those hours when renewable energy systems are feeding into the grid.

11 T45-Eelectricity scenario. This is a simplified diagram. The graph refers to work (TWh): 2023 a good 200 TWh wind+PV, 2045 a good 1,000 TWh domestic generation. In terms of capacity (GW), offshore wind requires expansion by a factor of 8 (from 8.4 to 70 GW), PV by a factor of 5 (from 82 to 400 GW), onshore wind by just under a factor of 3 (from 61 to 160 GW).

As a result, the achievable market revenues needed to refinance the investments, the so-called market values, will also decline. Investments are only made if there is at least the expectation of refinancing and the chance of making a profit. The electricity price-reducing effect of renewable energies is so high that they are often no longer able to refinance their own investment costs through market revenues. Current market value forecasts show that the market values for the majority of renewable energy plants are unlikely to be sufficient to refinance their investment costs.

This situation was **unanimously** recognised **as a central investment risk** for renewable energy sources in the working group on "Securing the financing of renewable energy sources" of the **Platform Climate-Neutral Electricity System**.

Another major investment risk for renewable energy sources is that electricity market revenues are uncertain. The pace of electrification, the extent of flexibilisation, the electricity costs of future price-setting capacities, the yield quality of future meteorological years and many other factors mean revenue risks for anyone investing in renewable energy plants, both in terms of the achievable prices and the quantity that can be produced. Investors cannot influence these revenue risks themselves. Nor can they hedge against these risks. As a result, these revenue risks increase the capital costs of the renewable energy plants, because the interest requirements of the investors increase. As renewable energy plants are particularly capital-intensive, the revenue risks have a particularly strong impact on the investment costs to be refinanced. As a result, the investment costs leveraged by rising capital costs are even more difficult to refinance with the low electricity market revenues.

Renewables will not be expanded only by the forces of the CO_2 market alone. To ensure that climate neutrality and the expansion of renewables are achieved solely via the European Emissions Trading Scheme would require very high CO_2 prices. In principle, high CO_2 prices increase the market revenues of renewable electricity generation and therefore also promote its refinancing on the market. However, investors cannot be sure whether the ETS will be bolstered by other measures in the future. In addition, due to the simultaneity effect, renewables often do not benefit from higher electricity prices as a result of higher CO_2 prices. Combined with a capital market that has an aversion to taking risks, this means that CO_2 prices are currently too low to enable all the required climate protection investments to be made, including investments in renewable energy sources, especially at the ambitious pace set by European emissions trading and the German expansion targets. At the same time, the CO_2 price level that would be necessary for purely market-driven renewable energy expansion would present major challenges for industrial CO_2 emitters and electricity-intensive companies, in particular with regard to their international competitiveness.

3.1.2 The future investment framework for renewable energy sources

A sustainable, reliable and cost-effective investment framework will secure the expansion of renewable energy sources and will give investors predictability

The above-mentioned challenges show that to ensure that investments in renewable energies that are necessary for climate protection and competitiveness of Germany's industry continue to be made and that they can develop their electricity price-reducing effect, the ramp-up of renewable energies needs a sustainable, predictable and cost-effective investment framework. A prerequisite for investments in renewable energy plants is a framework that gives investors a sufficient opportunity to fully refinance their investments, and to do so across the required renewable energy areas. For this reason, it is important that revenue risks in particular are limited due to the above-mentioned uncertainties. An investment framework can provide this risk management. The result will be that capital costs and thus the electricity production costs will fall. This can also help to reduce the problem of excessively high electricity prices (particularly for industry), especially when combined with greater flexibilisation of demand. Undesirable scenarios in which the very high electricity or CO_2 prices required for a renewable energy expansion in line with the targets would weaken Germany as a business location or fail to meet the expansion targets will be avoided by means of an investment framework. The Initiative for Growth states that renewable energy sources will no longer receive funding as soon as the electricity market is sufficiently flexible and sufficient storage capacity is available.[12]

In its Initiative for Growth at the beginning of July, the Federal Government confirmed that the expansion of new renewable energy plants should be switched to investment cost support (dedicated capacity mechanism), in particular to ensure that price signals are not distorted. To this end, this and other instruments are to be tested in the market as quickly as possible. At the same time, a high expansion momentum must be maintained to ensure that the targets set out in the Renewable Energy Sources Act are met and to obtain more cheap electricity as quickly as possible. In this way, even greater attention will be paid to cost effectiveness and market integration. At the same time, the options identified by the Platform Climate-Neutral Electricity System are to be examined and incorporated into the decision.

The sliding market premium has made a major contribution to the strong expansion

The sliding market premium as the status quo ensures that the expansion of renewable energies will continue and provides investors with a reliable framework – but is only temporary due to European legislation. The sliding market premium currently secures expansion in line with the targets by effectively hedging revenue risks. It is inherently cost-effective due to the competitive way of determining the amount of hedging required. The state's minimum price offers investors and financing banks a high degree of security. At the same time, it offers further advantages, such as incentives for the effective deployment of plants by allowing direct marketers of electricity to optimise their costs and revenues on the electricity market and respond to price signals, but also to incentives for an efficient design of the plants, which would allow a plant to optimise the individual market value of the electricity generated. The sliding market premium has thus brought renewable energy sources into the competitive world. It has proved to be successful in the past.

However, due to European requirements, the sliding market premium will no longer be legally permissible in Europe as of 1 January 2027. Instead, an additional repayment mechanism will have to be introduced ("clawback"). The recently reformed EU internal electricity market regulation[13] will also only allow direct price support schemes that include such a mechanism as of 2027.

The new investment framework must comply with European requirements and it will be necessary to examine how the system can be further optimised in order to further strengthen market integration with regard to effective investment incentives that benefit its use and the system.

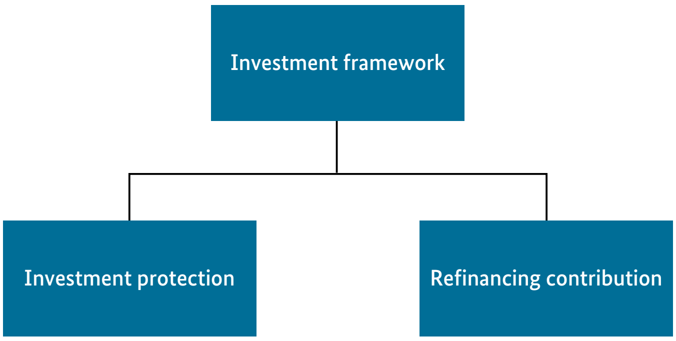
12 Federal Government (2024), point 42 letter b

13 European Union (2024)

The opportunity for the future: a further developed investment environment as a combination of protection of investments and refinancing contributions

The investment framework combines investment protection with a refinancing contribution. The two essential elements of an investment framework have already been identified: investments are to be protected, while at the same time the repayment mechanism prescribed by European law must be included (Figure 6).

Figure 6: Components of the investment framework for renewable energies



Source: own diagram

A further developed investment framework for renewable energies offers opportunities for operators and the state. The investment protection hedges revenue risks for the operator. Compared with the status quo, the new element also offers opportunities. Designed as a refinancing contribution, the repayment can be used on the one hand to strengthen the market segment of renewable energy expansion and on the other hand to get operators involved in refinancing their hedges:

- A refinancing contribution reduces capital costs for operators. With a refinancing contribution, the revenue situation of the system is kept at a constant level. This means that in the overall calculation of the investment, the uncertain electricity market revenues will have to be taken into account to a much lesser extent. This will reduce the cost of capital. Reduced capital costs will tend to be reflected in a lower hedging requirement.
- A refinancing contribution incentivises the most productive sites for renewable energy generation to enter the market and thus strengthens the long-term and predictable offer of green power purchase agreements (PPAs), i.e. the segment for expansion outside such an investment environment. This is because plant operators can avoid repaying additional market revenues only if they obtain refinancing exclusively by means of electricity market revenues.
- Ultimately, a refinancing contribution gives the state the possibility of utilising unexpected additional profits resulting from high price phases, to (partially) refinance investment protection, for example.

In order to enable the largest possible, purely market-based renewable energy segment, an investment framework should only protect those investments that would have no chance of obtain refinancing outside this framework. There will be some plants that can expect sufficiently high revenues from the electricity market, because they are developing very profitable sites, for example. These plants can be refinanced in the long term via green power purchase agreements (“green power PPAs”). However, the potential for these highly profitable sites is limited. In order to achieve the expansion targets and also climate neutrality, therefore, all usable sites are required. Segmentation will therefore be necessary: for such high-yield sites, refinancing outside the investment environment should be more attractive. In this case, requirements to participate in refinancing within the investment environment in particular will be relevant (see Chapter 3.1.3).

The success of the investment framework depends on it ensuring that the renewable energy expansion targets are achieved, while at the same time leveraging the potential available in terms of cost effectiveness and incentives for effective plant deployment and a plant design that benefits the system. The conversion costs for operators should also be as low as possible. The investment framework for new renewable energy plants can be designed in different ways and should be assessed on the basis of the criteria outlined below.

Expand renewables and bring down electricity prices (to achieve renewable energy expansion targets): the expansion of new plants should be adequately incentivised and at a sufficient pace to achieve the expansion targets. This can be done by closing the profitability gap and hedging the price and volume risk, in addition to using all appropriate sites needed to achieve the targets.

Reduce costs (cost efficiency): the desired goal should be achieved at the lowest possible system costs. For renewables, this means specifically: low funding costs (including capital costs and market-based refinancing of sufficiently profitable sites), but also a design of the renewable energy plants that benefits the system and integration into the electricity market (see Box 7 on incentives for effective plant deployment and a plant design that benefits the system).

Ensure continuity, acceptance and low complexity: introduction, enforcement and implementation of measures should be carried out at the least possible cost and effort and susceptibility to errors, in terms of the configuration, for example, should be minimised. Investment security is key to ensuring that approval and completion figures remain on track and costs continue to fall. Overall cost efficiency is just as important. Every system change leads to uncertainties and can lead to a temporary wait and see attitude (“break in continuity”). A longer transition period can reduce such risks. Each time the system is modified, it will be necessary to determine whether the desired benefits outweigh the risks, especially the risk of a “break in continuity” (Figure 7).

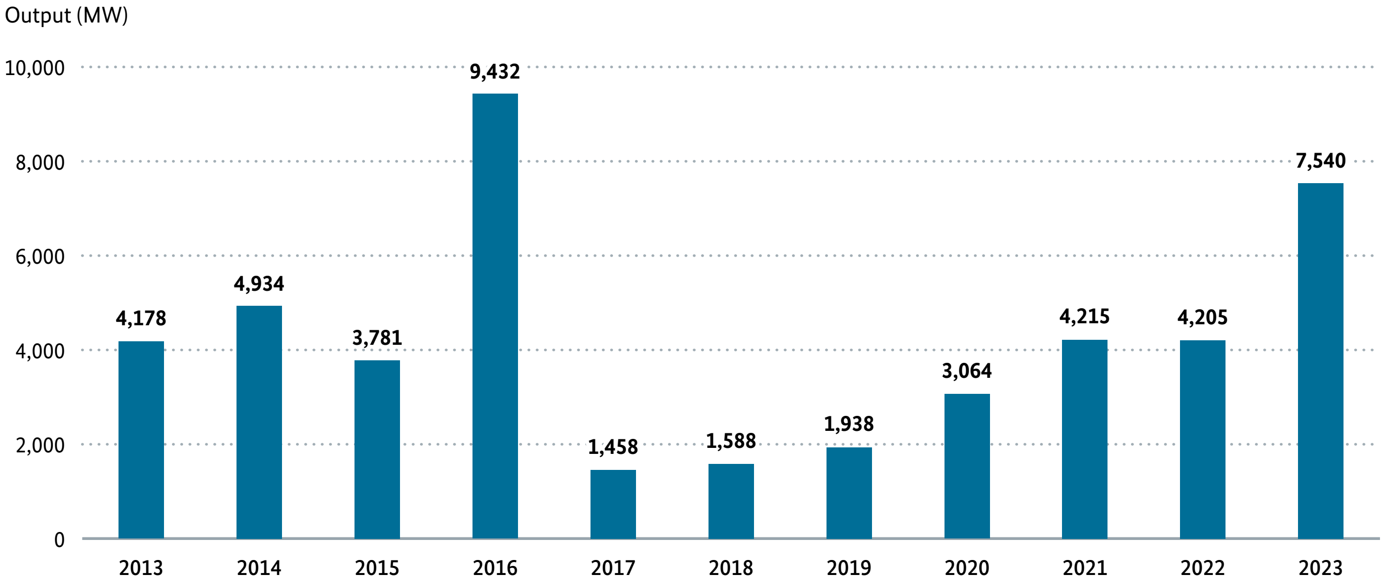
Box 3

Green Power-Purchase-Agreements

In future, state guaranteed hedging instruments for PPAs will also play a greater role in extending the refinancing segment for renewable energy plants to include the electricity markets. In the current market framework, longer-term PPA marketing is only available for offshore wind power plants and larger ground-mounted solar power plants. In future, plants in particularly good locations will continue to find buyers who purchase the electricity generated over sufficiently long periods at prices that enable sufficiently reliable refinancing of the investments.

PPA hedging instruments address a key obstacle in the PPA market: the creditworthiness of the buyer. This expands the circle of PPA users and increases the potential volume of the PPA market. However, it is still unclear how large the actual effect on the market will be if the terms of the hedging instruments are close to market conditions. The availability of sites that can refinance themselves from electricity market revenues alone is limited. Even a hedging instrument for PPAs cannot solve this challenge. The need for an investment framework for all renewable energy plants exists regardless of any supplementary hedging instrument for PPAs.

Figure 7: Development of newly approved annual wind energy capacity 2013 – 2023[14]



Source: Fachagentur Windenergie an Land 2024

Provide efficient use and system-beneficial investment incentives: installations in future should be incentivised even more to generate electricity when the market price is positive and not to generate electricity when the market price is negative. This will lead to plants being configured during their construction in such a way that the expected value of the electricity they produce is as high as possible (for example, by having an east-west orientation of solar PV systems or low-wind systems, where appropriate). The progress achieved on the basis of the sliding market premium should be maintained, but any remaining market distortions should be eliminated.

14 Example of the risk of a wait and see attitude: the break in continuity for onshore wind licences as of 2017 (i.e additional construction as of 2018) was a consequence of the switch to tenders in 2014: project developers focused on projects for which, in accordance with the transition period, they did not yet have to participate in tenders. New projects subject to tendering were delayed, partly due to these anticipatory effects and errors during the system changeover.

Box 4

Particular challenges of individual technologies and small-scale renewable energy systems

Biomass is a limited resource and should therefore be used in energy conversion in way that enables it to be used to cover peak loads and fully exploit its controllability. Biomass plants can operate regardless of the weather conditions and would therefore in principle also be suitable for competing with other controllable technologies. The technical prerequisites already exist to cover peak loads on the electricity market using biomass plants, which some plant operators make use of to optimise electricity prices. Despite the technical potential, the majority of the 10,000 plants in Germany are not flexible enough to benefit the system. There are arguments both in favour of locating biomass in the investment framework for renewable generation discussed here and in favour of locating it in the investment regime for controllable generation, both of which still need to be carefully weighed up against each other. In addition, biomass plants may be able to provide other valuable ecosystem services outside the energy system. General speaking, biomass should be used primarily in sectors that are otherwise difficult to decarbonise, such as transport (aviation and shipping) and industry.

Hydropower and geothermal plants are part of the current regulatory framework under the Renewable Energy Sources Act. For these technologies as well, it will therefore be necessary to examine how and in which investment framework they can be integrated. It is important to bear in mind that, in addition to electricity generation, the other purposes of hydropower plants can be fulfilled. This includes, for example, grid system stabilisation or the possibility that geothermal energy could focus exclusively on heat supply.

Small-scale renewable energy systems will continue to require an environment that is tailored to their specific strengths and challenges. The current system already permits special regulations for small-scale plants, in particular to strengthen acceptance and participation in the energy transition and to develop sites without additional land requirements. This applies, for example, to the exemption from the obligation to participate in a tendering process and, for very small plants, from the direct marketing obligation. Special regulations are also likely to be needed in a new investment framework, as requirements that are necessary and appropriate for large-scale plants can quickly become an obstacle to investment for small-scale plants, in view of the associated costs, which tend to jeopardise many projects. However, the aim is to maintain and strengthen the small systems segment for new plants. At the same time, however, there are challenges with regard to incentives for effective plant deployment, for example, and plant designs that benefit the system. Further in-depth examination is needed to determine how the framework conditions should be designed in a new investment framework for small-scale systems. In future, a large proportion of these systems will still consist of photovoltaic systems installed on rooftops by private individuals and used for their own consumption. According to the Renewable Energy Sources Act 2023, rooftop solar PV systems will account for half of the future expansion of photovoltaics. It is important in such cases, therefore, to find an intelligent way to combine the various objectives: expansion with little red tape, getting everyone involved, local consumption, incentives for effective plant deployment and a plant design that benefits the system, cost effectiveness and efforts to reduce negative prices.

3.1.3 Possible options for action for an investment framework for renewable energy sources

In the light of the PKNS discussion, four promising instrument classes have emerged, each of which are to be seen as an alternative approach (Figure 8):

Figure 8: Options for action for an investment framework for renewable energy sources

OPTION 1	OPTION 2	OPTION 3	OPTION 4
Production-based models		Non-production-based models	
Sliding market premium with refinancing contribution (two-way contract for difference with market value corridor)	Production-based two-way contract for difference with no market value corridor	Non-production-based two-way contract for difference	Capacity payment with non-production-based refinancing contribution

In principle, a new investment framework for the expansion of new renewable energy plants can be linked to a plant's actual electricity production or organised regardless of it. Logically, therefore, a distinction is to be made between two approaches:

- Production-based payments that are based on the plant's actual electricity production (e.g. sliding market premium with refinancing contribution, Production-based contract for difference).
- Non-production-based payments that are based, for example, on the electricity production potential, a reference plant's electricity production or a plant's output (e.g. non-production-based contracts for difference, capacity payments with refinancing contribution).

Production-based and non-production-based options for action have different characteristics, among other things with regard to the degree of system conversion and the incentives for the effective plant deployment and a plant design that benefits the system (see the following presentation of options in detail).

For their implementation, each of the options presented would require further examination with regard to the specific design. The options are instrument classes with a partially standardised basic philosophy and approach, but are not yet instruments that can be implemented immediately. Each option, however, actually comprises a large number of possible specific design variants that still need to be developed, examined and evaluated in detail. The functionality, opportunities and challenges of the options are presented below.

Each of the options for action presented in this section requires a different degree of further development. In particular, non-production-based investment frameworks offer benefits in terms of incentives for the effective plant deployment and a plant design that benefits the system. The increasing volume risk is also inherently addressed by non-production-based investment frameworks.

In its **Initiative for Growth, the Federal Government has agreed on the following**:

> *"... While electricity generation from renewable energy needs to be gradually integrated into the market, the further ramp-up of renewable energy requires a sustainable, reliable and cost-effective investment framework. As coal-fired power generation is ended, subsidies for renewables will be phased out. In future, the instrument of financial support for investment costs (separate capacity mechanism) is to be used to promote the expansion of new renewable energy sources, particularly to ensure that the effects of price signals are free from distortions. For this purpose, this instrument and others are quickly being tested in a market framework based on the Regulatory Sandboxes Act. At the same time, a continued high rate of expansion of renewable energy needs to be maintained in order to enable the targets set out in the Renewable Energy Sources Act to be achieved and to quickly provide as much affordable electricity as possible. In taking this approach, even greater attention will be paid to cost efficiency and market integration. In this context, the options presented as part of the Platform Climate-Neutral Electricity System will be examined and taken into account in the decisions made. In future, renewables will no longer receive funding support as soon as the electricity market is sufficiently flexible and sufficient storage capacity is available."*

The decisions taken by the Federal Government in its Initiative for Growth to switch from subsidies for renewables to financial support for investment costs (separate capacity mechanism) can be complied with under Option 4.

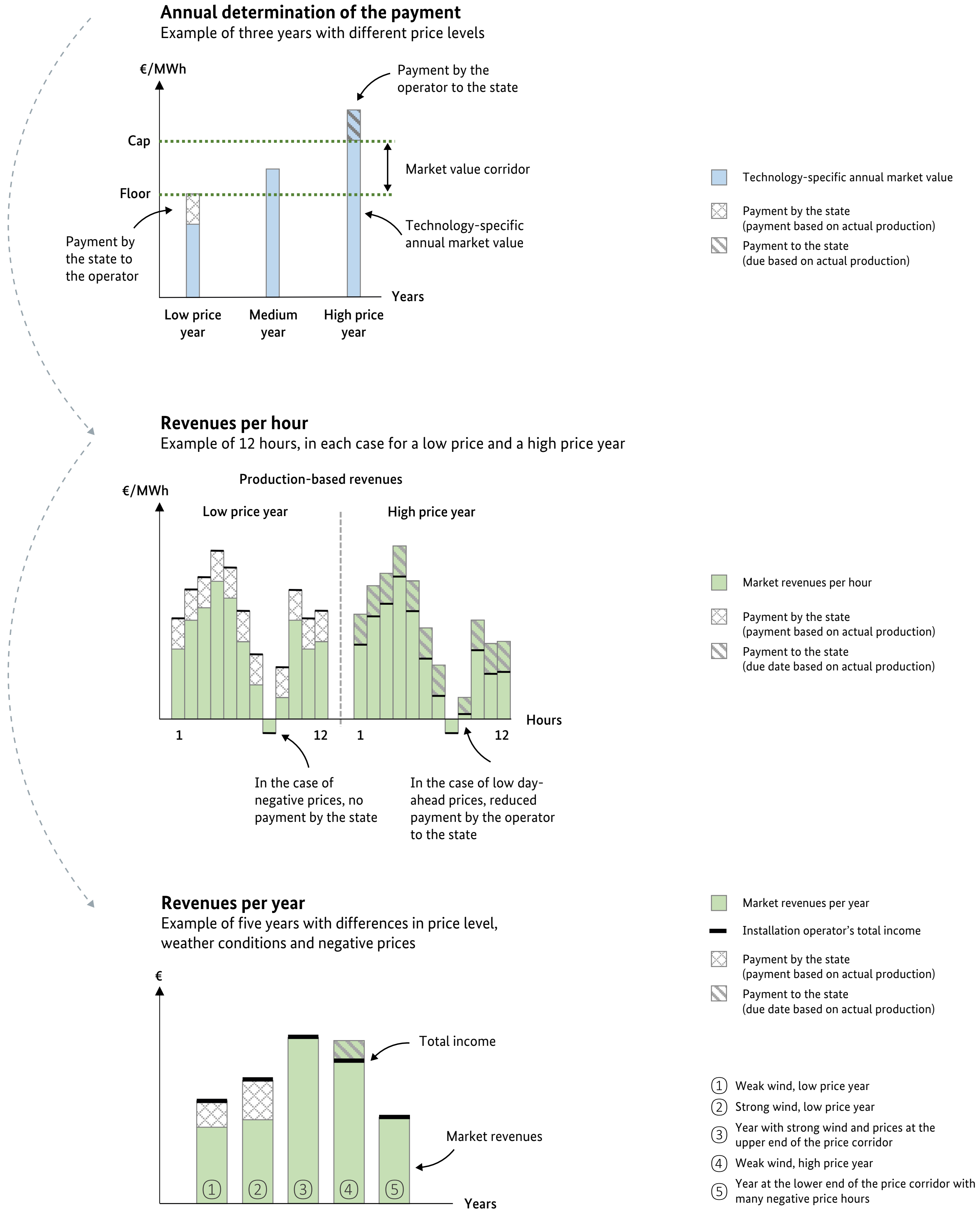
Option 1:
Sliding market premium with refinancing contribution (two-way contract for difference with market value corridor)

In the case of a production-based payment, as a form of investment protection – as is also the case in the status quo – the plant operator receives a variable payment for the kilowatt hours actually fed into the grid (payment per fed in kWh). The payment depends on a so-called value to be applied and a reference market price. As a form of investment protection, the plant operator receives the difference between the value to be applied and the average market price for the reference period provided the value to be applied exceeds this amount. Such a mechanism is already included in the Renewable Energy Sources Act as a so-called sliding market premium. The reference market price can be selected as a basic principle depending on different reference periods (e.g. monthly or annually), the current sliding market premium uses an annual reference period (technology-specific annual market value) to improve the incentives for effective plant deployment and a plant design that benefits the system. The marketing of the electricity volumes and the compensation for short-term forecast errors is carried out by the plant operator himself or by a third party he has commissioned (direct marketer). With the existing sliding market premium, a major step towards market integration has already been taken compared with the fixed feed-in tariff: since the revenues vary with the electricity price, the marketers respond to electricity price signals. In contrast, fixed, hourly revenues would represent a step backwards.

The sliding market premium should be supplemented by a refinancing contribution. In addition to that, an examination is needed to determine how it can be further optimised with a view to effective incentives for the use of and investment in plants that benefit the system. For the introduction of a refinancing contribution, in the case of the sliding market premium with refinancing contribution, the reference market price of the investment protection component ("floor") will be supplemented by a second, higher reference market price ("cap"). In the event that this cap reference market price is exceeded, the plant operator must repay any revenues that exceed the cap to the state. The refinancing contribution thus adheres to the same principle, but in reverse to that used to determine the payment. The result is that a "market value corridor" is created, within which no payment is made between the state and the operator. Below the floor, the market revenues are supplemented by a premium, while above the cap, the operator is required to make a refinancing contribution.

Figure 9 illustrates with the aid of three graphs the calculation of payments and revenues, taking the case of a wind power plant as an example in the case of the sliding market premium with refinancing contribution. The first graph illustrates the calculation of the amount to be paid with the example of three years with different price levels. The second chart shows the example of revenues for twelve hours in a low-price and a high-price year. The third chart takes the example of five years to show the possible annual revenues that can result from different prices and weather conditions.

Figure 9: Schematic principle of the sliding market premium with refinancing contribution



Source: Graphs prepared by Neon Neue Energieökonomik and Consentec on behalf of the BMWK

Opportunities:

- The sliding market premium is already a tried-and-tested instrument to ensure that the expansion of renewable energy is in line with the targets. Differentiated incentives for sites with different site quality can – and must – be achieved through tried and tested mechanisms such as the reference yield model.

- As the sliding market premium with refinancing contribution is closest to the current system of the applicable Renewable Energy Sources Act, the system changeover is comparatively uncomplicated. The refinancing contribution also adheres to the previously mentioned calculation principle (in reverse).

Challenges:

- The volume risk resulting from fluctuating weather conditions and uncertainties, in addition to the uncertain frequency of hours with negative prices, remains. This is the case because the payment made for hours with negative prices would be suspended in order to incentivise effective plant deployment. This potentially increases revenue uncertainty and thus capital costs. Those higher capital costs can increase the total costs of the investment framework. In extreme cases, the additional risks can affect the financing of the plants and thus jeopardise the achievement of the renewable energy targets. In view of the uncertain frequency of hours with negative prices, it will therefore also be necessary to examine and discuss models that address this risk by changing the current funding system so that the investment protection is based on electricity volumes or full load hours, for example, instead of years.

- The capital costs of the investment are a key determinant for the calculation of bids, as they tend to increase with a wider market value corridor (see Box 5). In addition, the price risk within the market value corridor will probably be difficult to hedge with the aid of forward transactions or PPAs.

- The annual reference period in principle always guarantees the short and medium-term electricity price exposure. However, when combined with the introduction of a refinancing contribution, the long reference period creates potential disincentives on the day-ahead electricity market, which can be addressed by means of a dynamic design of the refinancing contribution. In addition, the introduction of a refinancing contribution in certain situations incentivises plant operators, despite positive electricity prices, to shut down the plant and procure replacement volumes of electricity in short-term trading, so as to avoid any repayment. This makes a distortion in short-term trading probable. Such a distortion is likely to increase, the higher the hourly repayment level rises, and should therefore tend to rise, the lower the upper reference market price, i.e. the cap, falls. At the same time, it is therefore also likely to become more relevant as the share of renewables increases.

- Necessary correction mechanisms to improve effective plant deployment are likely to increase the implementation and conversion costs and effort.

This option is currently being examined further by the BMWK, but is unlikely to be pursued any further.

Option 2:
Production-based, two-way contract for difference without a market value corridor

With the production-based, two-way contract for difference without a market value corridor, the system operator also receives a variable payment for kilowatt hours actually fed into the grid (payment *per fed in kWh*) as investment protection. The mechanism of the investment protection and refinancing contribution corresponds to that of the sliding market premium with refinancing contribution (Option 1) – with a decisive difference: in the case of the two-way contract for difference without a market value corridor, the reference prices for the investment protection component and refinancing contribution (floor and cap), which are still different under Option 1, coincide. As a result, only one reference market price needs to be determined in this option. As a form of investment protection, the plant operator receives the difference between the value to be applied and the reference market price, provided that the value to be applied exceeds the reference market price. In the event that the reference market price is exceeded, the plant operator is required to repay the revenues exceeding the reference market price to the state.

Figure 10 illustrates the principle of a production-based, two-way contract for difference without a market value corridor for the same wind power plant taken as an example in Figure 9 for the case of an annual reference period.

Design variants with different reference periods: an important parameter for the degree of risk hedging required is the definition of the reference period. The length of the reference period for the reference market price to be applied can be hourly, monthly or annually, for example. It should be noted that choosing an hourly reference period would mean a step backwards in terms of the incentives for the effective plant deployment and a plant design that benefits the system. In the case of an annual reference period – as is the case with the current sliding market premium – increases in the market value as a result of a modified plant design and choice of location, for example, generally lead to higher revenues.

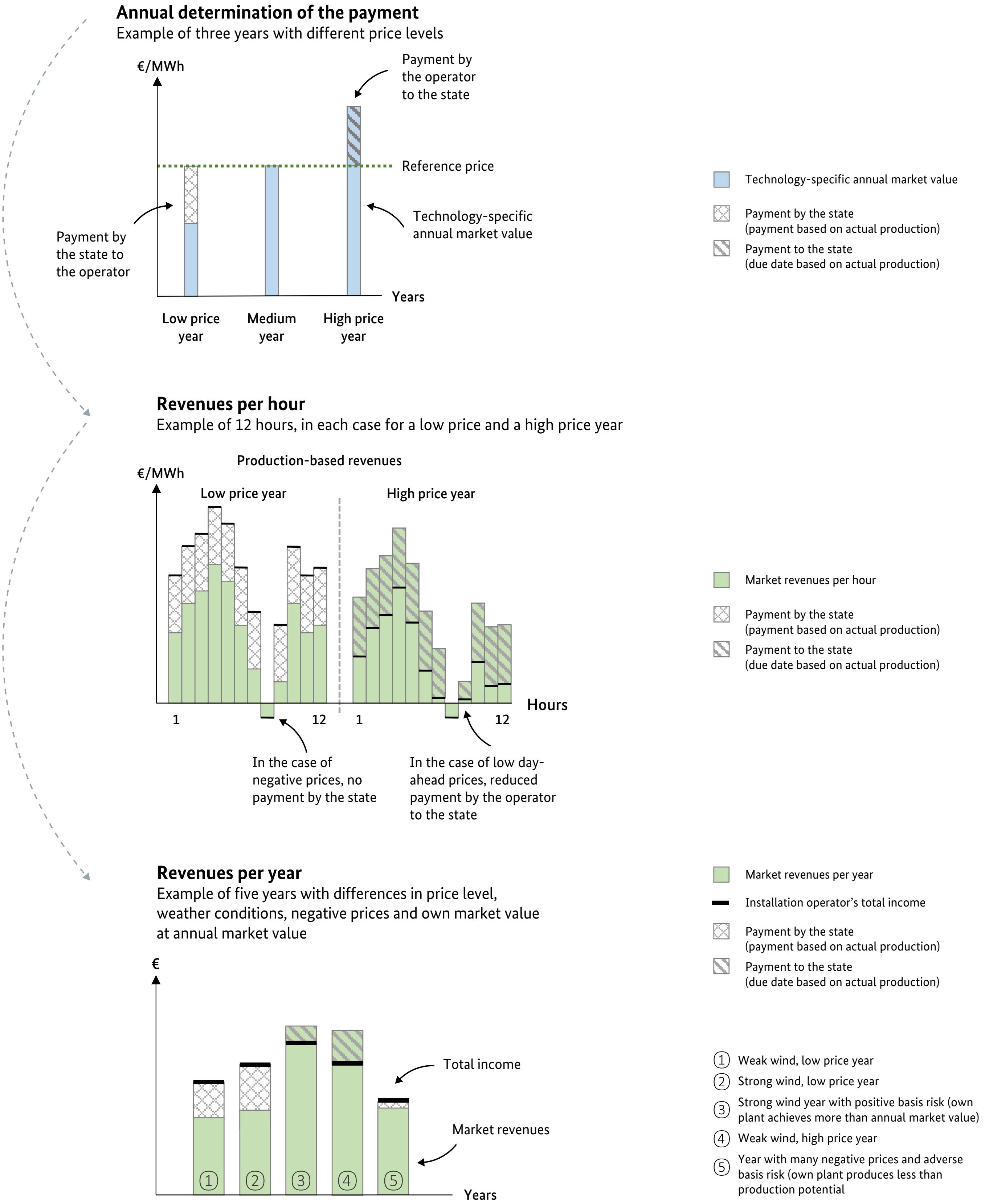
Opportunities:

- As a basic principle, production-based, two-way contracts for difference can ensure the expansion of renewable energy in line with the targets. Provided the determination of the maximum values, particularly in the tenders for the reference prices to be applied, allows sufficiently high values to be applied, the price risk will be hedged in the long term and the profitability gap will be closed. Under these conditions, this is a suitable instrument for incentivising the expansion of renewable energy plants to a sufficient extent. Differentiated incentives, even for poor sites, can – and must – be achieved through tried and tested mechanisms, such as the reference yield model.

- The capital costs of the investment are a key determinant for the calculation of bids. Compared with the design variant with a market value corridor, the capital costs are likely to be lower in the case of a production-based, two-way contract for difference without a market value corridor (see Box 5).

- The degree of electricity market integration varies greatly depending on the reference period chosen. In the case of a monthly to annual reference period, the short and medium-term electricity price exposure is at least partially

Figure 10: Schematic principle of a production-based, two-way contract for difference without a market value corridor



Source: Graphs prepared by Neon Neue Energieökonomik and Consentec on behalf of the BMWK strengthened. In the case of an hourly reference period, the investment framework provides no incentive for effective plant deployment and a plant design, which is why these variants should not be pursued further for the time being. Longer reference periods strengthen the incentives for an effective plant deployment, but lead to additional risks of deviation from the reference price on the producer side. The longer reference periods also create possible disincentives on the day-ahead electricity market, which can – and must – be addressed through a dynamic repayment regime.

- The production-based, two-way contract for difference without a market value corridor is also similar to the current system of the Renewable Energy Sources Act. Compared with the sliding market premium with refinancing contribution, the elimination of the market value corridor simplifies the bid calculation for bidders. Accordingly, the system changeover and the risk of a break in continuity in the renewable energy expansion are comparatively low. The repayment also adheres to the previously mention calculation principle (in reverse). The contract for difference is well-known from the cabinet draft for the Offshore Wind Energy Act 2023, for example, but also from other EU Member States.

Challenges:

- The volume risk arising from fluctuating weather conditions and uncertainties, in addition to the uncertain frequency of hours with negative prices, remains. This potentially increases revenue uncertainty and therefore the capital costs. Those increasing capital costs can then again increase the costs of the investment framework. In extreme cases, the additional risks can impair the financing of the plants and thus jeopardise the achievement of the renewable energy target.

- Even in the case of long-term reference periods with dynamic repayment, effective plant deployment is only partially incentivised, as plant operators have an incentive in certain situations to curtail the plant, despite positive electricity prices, and to procure electricity substitution quantities in short-term trading in order to avoid repayment. This makes a distortion in short-term trading likely. Such a distortion is likely to increase, the higher the hourly repayment amount is, and could therefore become more relevant as the share of renewable energy increases.

- Necessary correction mechanisms to make plant deployment more effective are likely to increase the implementation and conversion costs.

This option is currently being examined by the BMWK, but is unlikely to be pursued further.

Box 5

Market value corridors can increase capital costs

The capital costs of the investment are the key determinant of the calculation of bids. The more secure and predictable the plant operator's revenue stream is, the lower the capital costs. Hedging the revenue risk within the scope of an investment framework reduces the capital costs. The reduction of the capital costs is likely to be greater, the more certain the cash flow is. An investment framework with a market value corridor reduces this cash flow certainty:

In the case of investment frameworks with a market value corridor (as is the case in the status quo with the sliding market premium), plant operators are likely to include the expected market revenues in competitive tenders to reduce their bids. In such cases, the investment protection component alone, such as the reference market price, for example, will not cover the costs of the plant. The costs will only be covered by taking the (uncertain) market revenues into account. In view of the uncertainty of this cash flow, investors in the plant may add a surcharge to the capital costs. The capital costs will tend to increase, the wider the market value corridor becomes.

By comparison, cash flow certainty is higher for design variants without a market value corridor: while plant operators cannot plan to use any (uncertain) market revenues to finance the plant, they will instead, however, demand investment protection in competitive tenders that fully covers the investment costs of the plant, such as a sufficiently high reference market price, for example. Overall, the cash flow for refinancing the plant will become more certain. Investors in the plant may subsequently demand lower capital costs. Accordingly, the two-way contract for difference without a market value corridor can initially be expected to result in higher bids than with the sliding market premium that includes skimming above a market value corridor. However, these higher bid values are not likely to be reflected in higher costs for the investment framework, as they are likely to be offset by the revenues to be expected from the refinancing contribution.

Option 3:
Non-production-based, two-way contract for difference

In the case of a non-production-based, two-way contract for difference, plant operators receive a variable payment, as is the case with the production-based variant, which depends on the value to be invested and the average market value of the reference period – not for kilowatt hours actually fed in, however, but for kilowatt hours that could theoretically have been fed in ("production potential").

The payment is made regardless of the actual feed-in from the plant. The production potential is used to calculate the generating capacity of a plant that is theoretically achievable. For this purpose, depending on the design, the plant capacity will be taken into account, in addition to the specific meteorological, topographical and technical conditions, if applicable. Deviations between the production potential and the actual feed-in occur in particular if the plant is curtailed by the operator (any curtailments imposed by the grid operator are compensated for). The plant operator therefore receives the difference between the reference price to be applied less the market value for every kilowatt hour he could theoretically have produced as investment protection, provided that the reference price exceeds the market value – regardless of whether the plant has actually produced or not.

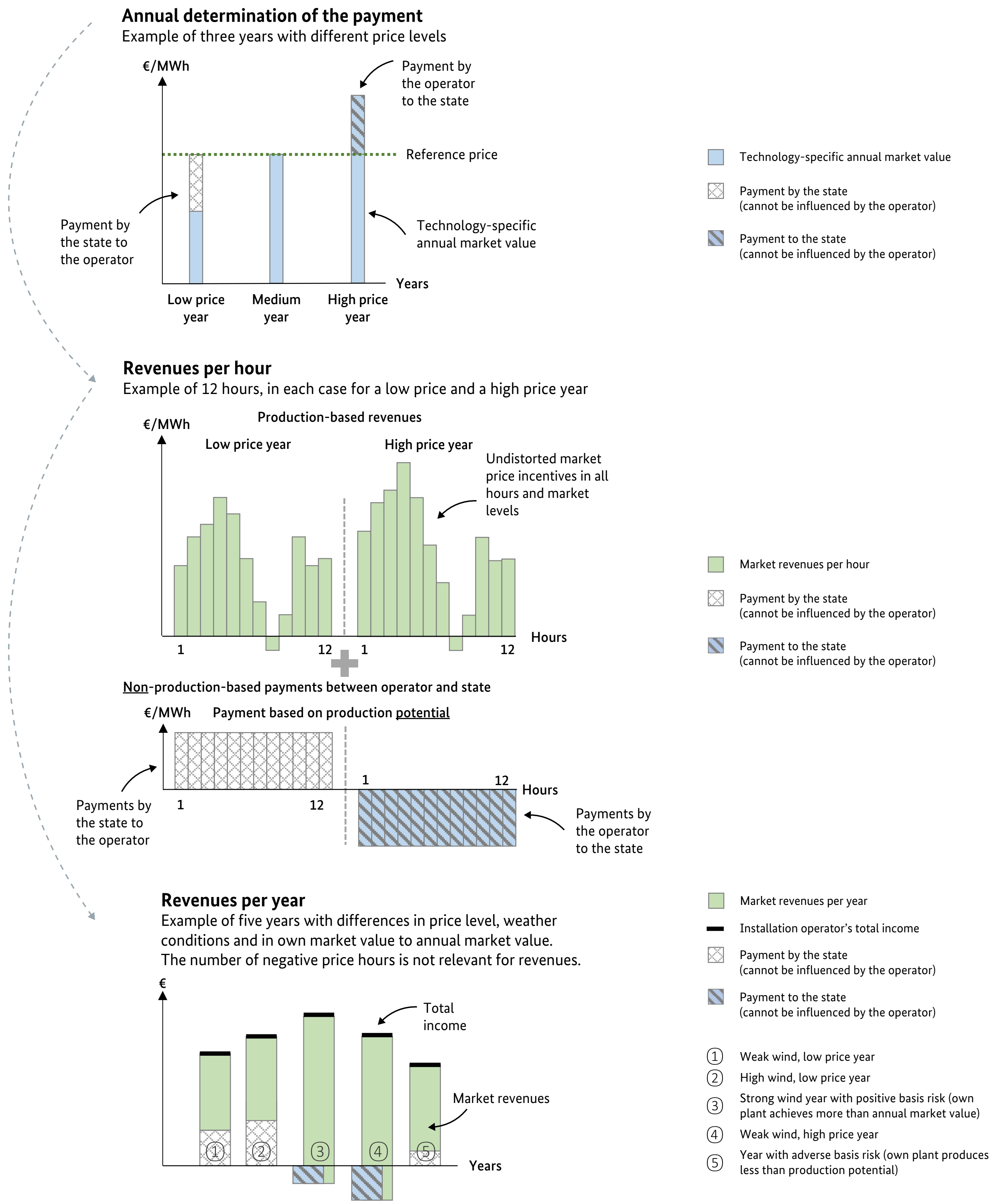
Similarly, as a refinancing contribution for every kilowatt hour that he could theoretically produce, the plant operator must pay the difference between the market value of the electricity that can theoretically be produced less the reference price, provided that the market value exceeds the reference price. This repayment obligation also remains in place, regardless of whether the plant actually produces or not.

Figure 11 illustrates the principle of a non-production-based, two-way contract for difference using the example of a wind power plant. In this schematic example, much like the example illustrated for Option 2, the amount of the payment by the state or the operator for an annual reference period is determined on the basis of the technology-specific annual market value for the entire year. In contrast to Option 2, however, the payment that is determined does not apply to every megawatt hour produced by the specific plant, but instead refers to the production potential, which is why the second schematic in this illustration is divided into two parts. The upper graph now shows the hourly production-based market revenues, while the lower graph shows the hourly payments that are not based on production.

The aim and purpose of calculating the payments within the investment framework on the basis of production potential instead of actual production is to completely decouple these payments from the actual deployment of the plant. For this reason, the plant operator is fully exposed to all electricity price signals with no distortion whatsoever. In particular, the plant then no longer has any incentive to curtail when prices are positive or to continue production when prices are negative. In other words, plant deployment becomes cost-effective.

Design options for determining the production potential: the effect of the instrument is largely dependent on the choice of reference for calculating the production potential. There are various design options for this, such as a plant-specific calculation or one based on a weather model or a reference feed-in quantity (see Box 6 for details).

Figure 11: Schematic principle of a non-production-based, two-way contract for difference



Source: Graphs created by Neon Neue Energieökonomik and Consentec on behalf of the BMWK

Box 6

Options for determining production potential

Plant-specific measurement of local weather data using a technical measuring system integrated into the plant

Under normal operating conditions, the production potential in this design variant should correspond approximately to the actual feed-in. This has the benefit of being highly accurate and reduces the additional risk of a possible deviation from the reference production. Site specific conditions would be compensated for, so that plants with a lower average site quality would also be incentivised. The challenge, however, would appear to be the nationwide deployment of the measuring system required at acceptable costs, any standardisation, including the establishment of a certain industrial standard of measurement, protecting the integrity of the measurement, among other things, against manipulation, in addition to sufficient transparency. At present, it does not seem certain that the technical and administrative implementation of this option will be possible at the pace required and at reasonable cost.

Measuring production potential using a weather model

As an alternative to the measurement of weather data by the operator on site at the plant, it is also possible to obtain weather data from external sources (currently in most cases from commercial and proprietary weather services) and to use these data as a basis for calculating the production potential. These are generally based on weather models. Due to their effects on efficiency levels and power curves, in addition to solar radiation and wind speed, however, it is likely that temperature and air pressure will also have to be recorded so that values that are completely independent of operator measurements are possible. The technical obstacles may sometimes be easier to overcome than with plant-specific measurements. For the success of this variant, however, it is essential that sufficiently accurate, high-quality and transparent weather data that are publicly accessible can be obtained. Levelling out site differences will also depend on this being done. If this is not possible within the scope of the weather model, further correction factors might be necessary.

Payment per kWh at the level of the average feed-in quantity of all/several plants of each technology

Ultimately, the average feed-in quantity of a defined number of plants using the same or different technologies could also be used, regardless of the weather data. This would offer the benefit of having a technically and administratively simple implementation. However, the risk for the individual plant of deviating from the reference production is likely to be significant and would therefore impair cost effectiveness and possibly jeopardise the achievement of the targets. In particular, site differences would have to be compensated for by additional correction factors in order to ensure that the renewable energy targets are achieved (in this case, weather data could be partially included again). What is simplified primarily in this case compared with measuring production potential solely on the basis of a weather model would be that the correction factor would have to be determined once or only at long (e.g. multi-year) intervals and not continuously in real time. This would also help to reduce the weather model requirements.

The main challenge of a non-production-based investment framework is likely to be found in its technical and administrative feasibility. This applies to both the plant-specific measurements and the estimated data using a weather model, albeit in different ways (see above on design variants). It currently seems unlikely that a solution to all the unresolved design issues will be possible in the short term. In the worst-case scenario, a switch to non-production-based measurement could prove to be technically unfeasible.

Opportunities:

- Provided that the values to be applied are sufficiently high, particularly in the tenders, the price risk will be hedged in the long term and the profitability gap closed. In such a case, production-based and non-production-based variants are likely to be virtually indistinguishable from each other.
- By decoupling payments from the investment framework and the plant operation, the plants are exposed to all electricity price signals in the short and medium term, which incentivises the effective plant deployment and a plant design that benefits the system. The incentives to deploy the plants and incentives for a plant design that benefits the system are stronger and more direct than is the case with production-based hedging and are already inherent in the instrument. In contrast to production-based payment, the efficient deployment incentives are also maintained undistorted in the intraday market. In contrast to an investment framework based on production-based payments, the decoupling of payments from plant deployment eliminates the volume risk due to negative prices (the weather-related volume risk nonetheless remains). There are no disincentives for production in times of negative prices: in this model, plant operators are completely incentivised not to operate the plant in hours of negative prices. Should the plant nevertheless be operated during these hours, the negative prices are borne entirely by the plant operator. Special regulations for hours of negative prices and the associated bureaucratic effort no longer apply.
- In principle, both price and volume risks are hedged extensively, which further reduces the capital costs.
- The non-production-based payment means that most market distortions do not arise in the first place, so that additional correction mechanisms, such as dynamic repayment or special regulations for hours with negative prices, can probably be dispensed with.

Challenges:

- As a result of the decoupling from the actual feed-in, the system changeover will require considerable cost and effort. As a result, there is a significant risk that market participants will initially be reluctant to invest in plants commissioned after the system changeover if the introduction of the new instrument is not adequately prepared and communicated. As regards plants with lower site quality, different site-dependent correction mechanisms will be required depending on the design variant selected in order that plants with average site quality are incentivised. Depending on the design, this can be achieved by further developing the current reference yield model, while alternative correction factors may have to be implemented (see the reference to design variants above).

- Plant operators are likely to be exposed in varying degrees to a new and "unproductive" risk (i.e. not associated with incentives that are desirable from an energy industry perspective), so that – even following any site-specific corrections – the plant will deviate from the reference plant to an extent that was not foreseen when the bid was submitted. This "basis risk" can increase the costs, with corresponding effects on the bid values, and in extreme cases can impair the financing of the plants and thus jeopardise the achievement of the renewable energy targets. This risk is all the greater, the less plant and site-specific the estimate of potential is. In the case of plant-specific measurements, the additional risk of deviations from the reference should be manageable. However, depending on how the production potential is measured, the measurement technology to be implemented will drive up costs.

- Switching from production-based payments in the current system to non-production-based payments means a major system change that could require a considerable adjustment on the part of the various actors involved.

- As already mentioned above, the main challenge is likely to be found in the technical and administrative feasibility.

This option is currently being further examined by the BMWK.

Option 4:
Capacity payment with non-production-based refinancing contribution

In the case of a capacity payment, the plant operator receives a payment for the installed capacity of a renewable energy plant as investment protection, i.e. a fixed payment *per kW*. The payment is initially – i.e. before being combined with a refinancing contribution – by its very nature not based on the plant's production. The payment can – and should – be spread over a longer period of time.

If the capacity payment is supplemented by a refinancing contribution, incentives for the effective deployment and a design of the plant that benefits the system are only provided when combined with a refinancing contribution that is not based on the actual feed-in from a plant. The incentive can be implemented in a similar way to Option 3, i.e. based on a production potential determined for a specific plant using weather models or on the production of individual or several reference plants (see Box 6). The feed-in incentive of the plant is dependent very much on the combination with a repayment instrument and is influenced significantly by the repayment instrument. The capacity payment is also only legally permissible in combination with a repayment mechanism. The capacity payment with non-production-based repayment works in the same way as contracts for difference without a market value corridor if the plant operators have to pay the market revenues from electricity generation, which is calculated on the basis of production potential in full as a refinancing contribution. In this case, this means that that the capacity payment is combined with a non-production-based contract for difference with a reference price of zero.

Incentives combined with a production-based refinancing contribution, on the other hand, are not effective: in such a case, the plant operator could avoid repayment of the market revenues by shutting down the plant and would de facto be incentivised not to produce electricity with the plant any time it suited him. Conversely, non-production-based skimming ensures that the plant operator is fully exposed to all electricity price signals and subsequently the feed-in incentive as well.

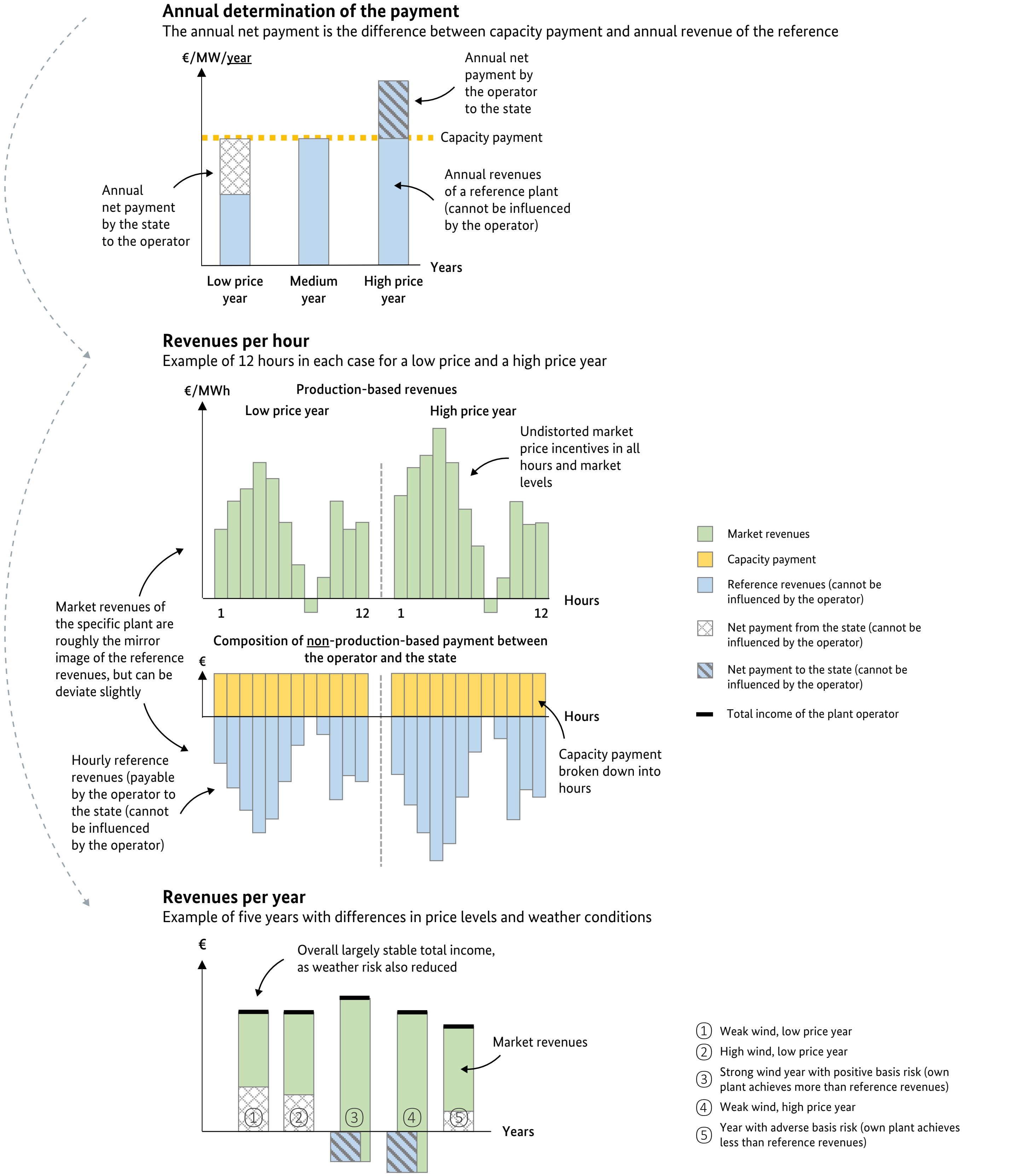
The operator's payment is then calculated as the difference between the capacity payment and the market revenues of the reference plant or the production potential. In the same way as for the value to be applied in the current system, the capacity payment can be determined in a competitive process. The operator keeps his own market revenues in full, so that his total revenues are made up of the combination of market revenues and payment.

Figure 12 illustrates the principle of the capacity payment with non-production-based refinancing contribution, once again taking the example of a wind power plant. A special feature of this instrument can already be seen in the first graph. The amount of the capacity payment is not based on the technology-specific annual market value and is therefore identical in each of the years. As in Option 3, two components of the hourly revenues are shown: the production-based revenues generated on the electricity market and the payments between the operator and the state, which flow regardless of the feed-in volume.

Opportunities:

- Since the hedge is not based on the revenues generated by a plant, the profitability gap of the plants is always closed. The decisive factor in this case is an adequate structure of the capacity payment and refinancing contribution.
- As a result of the decoupling of payments from the investment framework and plant opera-

Figure 12: Schematic principle of a capacity payment with non-production-based refinancing contribution



Source: Graphic created by Neon Neue Energieökonomik and Consentec on behalf of the BMWK tion, the plants are exposed to all electricity price signals in the short and medium term, which incentivises effective plant deployment and a plant design that benefits the system. The incentives for plant deployment and incentives for a plant design that benefits the system are stronger and more direct than is the case with production-based hedging and are already inherent in the instrument. In contrast to the production-based payment, incentives for the effective plant deployment also remain undistorted in the intraday market. There are no disincentives for production in times of negative prices: in this model, plant operators are completely incentivised not to operate the system in hours of negative prices. Should the plant nevertheless be operated during these hours, the negative prices are borne entirely by the plant operator. Special regulations for hours of negative prices and the associated bureaucracy no longer apply.

- A secure revenue stream offers the plant operator planning security. As a result of the greater security, capital costs can also be reduced, which can lead to lower overall costs and funding costs. In principle, both price and volume risks – in contrast to Option 3, not only due to negative prices, but also due to weather risks – are fully hedged, which further reduces the capital costs.

- Hedging by means of a capacity payment itself would be easy to administer. However, during the implementation and parameterisation of the refinancing contribution, the same complexities generally arise as with other non-production-based payments (see also the challenges of Option 3)

Challenges:

- The main challenge with capacity payments is maintaining the incentives for a plant design that benefits the system, in addition to the incentives to actually feed in electricity and to invest in the maintenance of the plant, for example, even when electricity prices are low. Measuring the hedging component of the investment framework based on the capacity of the plants, carries the risk of incentivising the design of the plants solely with regard to capacity (for example, a large generator of a wind power plant), but not necessarily to achieve a high production (for example, sufficiently large rotor diameters). Appropriate incentives must therefore be provided by adjusting the capacity payment or implementing the refinancing contribution to be compatible with incentives.

- As in the case of the non-production-based calculation of investment protection based on production potential for non-production-based contracts for difference (see Option 3), a new risk may arise to the extent that actual electricity market revenues may deviate from the electricity market revenues on which the calculation of the refinancing contribution is based. This “basis risk” can increase the costs, with corresponding effects on the bid values and, in extreme cases, impair the financing of the plants.

- **Continuity:** the switch to a capacity payment represents the biggest system change compared with the sliding market premium. The determination of the production potential or the reference plant must be examined further, in particular to include less profitable sites as well.

- Furthermore, the respective pros and cons of the chosen design variant of the refinancing contribution will be passed on.

This option corresponds to the approach outlined in the Initiative for Growth and is therefore being examined further by the BMWK.

Box 7

Incentives for effective plant deployment and a plant design that benefits the system will become even more important in the future

The options for action for shaping the investment framework for renewable energy sources differ, among other things, in terms of the incentives they provide for effective plant deployment and a plant design that benefits the system. A new investment framework for renewable energy sources can and should contribute to further improving the incentives for efficient operation and the design of renewable energy plants that benefit the system.

The design of renewable energy plants that benefits the system will become even more important in the future. With an increasing number of hours in which wind and solar PV systems feed into the grid simultaneously, it will become more important to design plants in such a way that a greater proportion of electricity is generated during hours with lower wind speeds or less solar radiation. For example, the orientation of a solar PV system (east-west orientation) or the height of a wind turbine and the length of its rotor blades in relation to the respective generator are key factors. In principle, the Renewable Energy Sources Act already incentivises a plant design that benefits the system with the sliding market premium, which is calculated in relation to the technology-specific annual market value. As a basic principle then, it is therefore attractive to optimise the individual market value of the electricity produced with respect to the average technology-specific annual market value by designing the system accordingly. In individual cases, however, height restrictions or shutdown requirements, for example, can – and in future are likely to – take precedence over a plant's optimisation based on the market value.

The need to introduce repayment components, depending on their nature, will have different effects on incentives for an effective plant deployment and a plant design that benefits the system. These will have to be taken into account in the assessment and precise design of the instruments (see the detailed description of the individual instruments). Minor distortions may still be acceptable in the case of 200 TWh of wind/PV electricity, but may no longer be so in the case of 1,000 TWh.

A new investment framework will therefore focus on cost effectiveness by incentivising effective plant deployment and a plant design that benefits the system. As the share of renewable energy plants increases, it will become increasingly important to provide these incentives for a future investment framework. To this end, the price signals from wholesale electricity trading should reach the plants with as little distortion as possible.

In this respect, there are certain differences in the way production-based and non-production-based instruments work. Instruments that are linked to the amount of electricity actually produced can also be designed in such a way that the electricity price signals can have a predominant effect. It is likely, however, that these production-based instruments will always retain increasingly small market distortions – particularly on the short-term markets.

Moreover, the number of hours with negative prices is also expected to increase further in the future. The uncertainty surrounding this alone can limit project profitability. It is becoming increasingly important in project planning to keep the volume risk due to negative prices manageable.

Non-production-based investment frameworks in particular may be able to address these challenges even more effectively. Any market distortions that remain and the increasing volume risk due to increasing hours of negative prices and uncertain weather conditions are both inherently addressed by non-production-based investment frameworks. Whether these models can actually be implemented in practice and with acceptable transaction costs cannot be conclusively assessed at present and will have to be discussed with stakeholders. The benefits of non-production-based instruments that result from even clearer signals for effective plant deployment and a design that benefits the system will also have to be weighed up against the considerable effort required for the system changeover and possible disruption to expansion that could accompany their introduction.

Summary of the investment framework for renewable energy sources field of action:

- While electricity generation from renewable energy sources will have to be gradually integrated more strongly into the market, the further ramp-up of renewable energy sources requires a sustainable, reliable and cost-effective investment framework in order to maintain and further increase the expansion momentum for wind and solar PV.
- A modified market framework will be required from 2027 in order to comply with European requirements for the introduction of a repayment mechanism.
- The choice will be between production-based and non-production-based investment frameworks.
- Non-production-based investment frameworks in particular offer benefits in terms of incentives for effective plant deployment and a design that benefits the system. In addition, the increasing volume risk is inherently addressed by non-production-based investment frameworks.
- In its Initiative for Growth that was published at the beginning of July, the Federal Government confirmed that the expansion of new renewable energy plants should be switched to investment cost support (dedicated capacity mechanism), in particular to ensure that price signals are not distorted. To this end, this and other instruments are to be quickly tested on the market. A continued high rate of expansion needs to be maintained in order to enable the targets set out in the Renewable Energy Sources Act to be achieved and to quickly provide as much affordable electricity as possible. In taking this approach, even greater attention will be paid to cost effectiveness and market integration.
- In this context, the options presented within the framework of the Platform Climate-Neutral Electricity System will be examined and incorporated into the decision.

Key questions for the consultation:

1. Do you agree with the assessment of the opportunities and challenges of the options mentioned above?

2. How do you assess the effects of the various options and design variants on effective plant deployment and a plant design that benefits the system? Please consider the following aspects:
   - How relevant in your opinion are revenue uncertainties when submitting bids due to forecast uncertainties of hours with zero or negative prices per option?
   - How do you assess the relevance of intraday distortions caused by production-based instruments?
   - What effects would an implementation of the options mentioned above have on the forward marketing of electricity from renewable energy plants? Do the effects differ for the various options? Do you expect to see any effects on the forward marketing of electricity by the retention and width of any market value corridor?

3. How do you assess the effects of the various options and their design variants on capital costs? Please consider the following aspects:
   - What differences in capital costs do you expect when comparing an investment framework with and without a market value corridor?
   - What capital cost effects do you expect from design options that are intended to enhance effective plant deployment and a design that benefits the system (e.g. through longer reference periods, measurement of payments based on estimated production potential or reference plants, etc.)?

4. How do you assess the effects of the various options and their design variants with regard to their technical and administrative feasibility and possible system changeover? Please consider the following aspects:
   - How do you assess the challenges and opportunities of a system changeover?
   - How do you assess the feasibility of a model with non-production-based payments based on local wind measurements and the feasibility of a model with a non-production-based refinancing contribution based on weather models?

3.2 An investment framework for controllable capacities

3.2.1 Ensuring resource adequacy in the decarbonised electricity system

The secure supply of electricity is a valuable asset for Germany as a business location.

Germany has enjoyed a very high level of resource adequacy for years. With a reliability standard of 2.77 hours per year[15], Germany has one of the most stringent reliability standards in Europe. This is met when the electricity market can fully cover demand in Germany for more than 99.96 per cent of the hours. Reserve power plants are also able to secure the electricity supply (see Box 10). In practice, however, demand has been met every hour of each year to date. This was even the case in the crisis year 2022, when an unforeseeable "triple crisis" occurred consisting of the loss of Russian gas supplies, the extensive outage of the French nuclear power plant fleet and a prolonged drought in parts of Europe, which led to power plant outages due to a lack of river cooling and reduced availability of hydropower plants, which caused significant shortages in European electricity generation.

Also the Federal Network Agency's current resource adequacy assessment does not expect any security of supply deficits by 2030. This also applies even when assuming there will be a complete coal phase-out by 2030.[16] To this end, the resource adequacy assessment identifies a number of measures that need to be taken, in particular the accelerated expansion of renewable energy sources and the grids. An increase in new and modernised power plants with capacities of 17 to 21 GW has also been identified. These are already being addressed by existing instruments such as the Combined Heat and Power Act, in addition to new measures such as the Power Plant Strategy.

Resource adequacy will also be guaranteed in a decarbonised electricity system, but it will be based on a different approach

Base load generation from large-scale fossil-fueled power plants will be replaced by wind and solar PV. In the current conventional electricity system, resource adequacy has been essentially guaranteed by large-scale fossil-fueled power plants. These large power plants were able to operate at base load, i.e. they could generate electricity almost continuously. In a decarbonised electricity system, however, there is no longer any need for this base load. Instead, wind and solar PV will generate most of the electricity at very low generation costs, since they have no fuel costs.

In order to ensure resource adequacy in the future, a mix of technologies with new back-up capabilities is needed. To ensure resource adequacy even when wind and solar PV are not sufficient to meet demand, the electricity system will need a back-up. Such back-up technologies will have to fulfil two requirements: Firstly, they must be able to balance out fluctuating electricity generation from wind and solar PV in the short term, i.e. they must provide **short-term flexibility**. Secondly, in rare cases, they must also be able to cope with several days or even weeks of low wind and solar PV generation (so-called "Dunkelflaute" or

15 Note: The reliability standard and the methods used to calculate it are governed by EU law and the European regulatory authority ACER. In addition to the security of supply standard, the SAIDI index is also frequently mentioned as an indicator of security of supply. It should be noted that the SAIDI takes into account all forms of supply interruption, including, for example, many local, short-term interruptions due to construction work, storms or similar. The reliability standard, on the other hand, considers at a national level whether there is sufficient generation capacity to meet demand.

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anticyclonic gloom) and provide seasonal balancing, i.e. they must be able to provide **long-term flexibility**.

As shown in Chapter 2, a technology mix of controllable capacities consisting of flexible power plants (including bioenergy and CHP plants), storage and demand response is ideally suited to do this. The use of storage systems and demand response can compensate for fluctuating renewable energy generation primarily in the short term, but have no fuel and CO_2 costs. By contrast, power plants can also supply electricity over a period of several weeks, but at comparatively high fuel costs. In a decarbonised electricity system, they mainly use hydrogen or biogenic fuels for this purpose.

Box 8

The Power Plant Strategy and the interaction with a capacity mechanism

With the Power Plant Security Act, a total of 12.5 GW of new, controllable power plants are to be quickly put out to tender as a no-regret measure in anticipation of a future technology-neutral capacity mechanism. In this way, the Federal Government is taking an important step towards the decarbonisation of the power plant fleet, namely the conversion from natural gas to hydrogen power plants.

In a first pillar, 5 gigawatts of new H2-ready gas-fired power plants and 2 GW of comprehensive H2-ready modernisation projects are to be tendered in the near future, which must switch to green or blue hydrogen operation in accordance with the National Hydrogen Strategy as of the eighth year following their commissioning/modernisation as a contribution to the rapid decarbonisation of the power plant fleet. In addition, there will be 500 MW of pure hydrogen power plants that run immediately on hydrogen (hydrogen sprinters) and 500 MW of long-term storage. In the case of power plants, funding will be provided for the investment costs and, following the changeover to hydrogen, for the differential costs between hydrogen and natural gas for 800 full load hours per year.

In a second pillar, a further 5 gigawatts of new gas-fired power plants, which will contribute to resource adequacy, in particular during periods of a Dunkelflaute, will be tendered.

The Power Plant Security Act provides a threefold boost in the power plant sector. Firstly, the decarbonisation of the power plant fleet will be accelerated, as a specific hydrogen transition pathway has now been agreed for some of the power plants; secondly, the development of new hydrogen power plant technology will be funded; and thirdly, the coal phase-out will be ensured through the construction of new power plants.

As part of the agreement on the Power Plant Security Act, it was also decided that a comprehensive capacity mechanism should be in place by 2028 at the latest. Power plants constructed under the Power Plant Security Act will be integrated into the future capacity mechanism. This means that they will be taken into account in the design of the comprehensive capacity market and will subsequently reduce the need for additional capacity, which will be incentivised and financed via a capacity market. Double funding is avoided and is also not legally permissible.

The introduction of a comprehensive capacity mechanism is a fundamental pathway decision that is associated with a permanent system change. The Power Plant Security Act does not anticipate this development, but will be compatible with the future comprehensive capacity mechanism.

3.2.2 The future investment framework for controllable capacities

Improvements to the investment framework required

At the same time, power plants in particular will have significantly fewer operating hours in a decarbonised electricity system than is the case today. The increasing share of renewable energy sources and the greater use of short-term flexibility options, such as storage and demand response, will reduce the hours in which power plants are needed. This is, on the one hand, good, because it reduces emissions and helps to lower wholesale electricity prices. However, it also reduces the periods of secure electricity market revenues for the power plants.

Within the Platform Climate-Neutral Electricity System (PKNS), therefore, the question was discussed as to what extent the current market design is sufficient to provide the investment security needed to incentivise the new investments required. On the one hand, there was broad consensus that new investments can generally be refinanced in the current market design, as they are controllable and can therefore generate high electricity revenues in times of high electricity prices. There is also the possibility of having long-term contracts to hedge against electricity price peaks. At the same time, however, the stakeholders pointed out in the discussion in the PKNS that key framework conditions have changed since the last market design debate in 2014/15:

- The coal phase-out agreed by law in 2020 and the associated phase-out pathway are changing the power plant fleet. Similar decisions have been taken in neighbouring countries.
- As a result, overcapacities of fossil-fueled power plants in Germany – and across Europe – are declining faster than was assumed ten years ago.
- The energy transition has accelerated significantly: the expansion of renewable energy sources, increasing cross-border electricity trading and new flexibilities (sector coupling technologies, such as e-mobility and electrolysers) are also changing the electricity market – technically and economically faster and more disruptively than was assumed ten years ago.
- This leaves less time for adjustments and at the same time requires new back-up capacity to be added more quickly. Revenue uncertainties have subsequently increased overall.
- Stakeholders also emphasised that the experience gained in the course of the last few years has reinforced the impression among investors that political interventions in the electricity system are to be expected when energy prices are high.

In short, the stakeholders considered an improvement in the current investment framework necessary.

A strengthening of the investment framework would therefore appear to be necessary, particularly for investments with longer refinancing periods. Based on the discussion in the PKNS and as part of the Power Plant Strategy, the BMWK therefore concludes that the current framework for investments in controllable capacities does not offer sufficient investment security and should be supplemented by a capacity mechanism. This applies in particular to capacities with a longer-term refinancing horizon that are particularly capital-intensive. This is where the problem of timeline mismatch arises. On the electricity market, hedging products are generally only traded in liquid form up to three years in advance, whereas capital-intensive investments have a refinancing horizon of up to 15 years.

A capacity mechanism complements the existing electricity market, but does not replace it. A capacity mechanism would represent a second, additional market segment for capacities. The wholesale market retains its coordinating function based on the merit order, i.e. it controls the effective deployment of all available capacities and cross-border electricity trading when needed and ensures that all consumers receive the most favourable offer of electricity generation, the cheapest "kWh", at all times across Europe. Additional marketing revenues for all capacities result, therefore, from the wholesale market. This must also be taken into account when designing the capacity mechanism.

Additional reserves are available for rare or unforeseeable crises. Both the Energy-Only Market and a capacity mechanism are only designed to deal with known and regularly occurring fluctuations in supply and demand or bottlenecks. In addition, however, there are very rare or unforeseeable events that the market and market participants cannot anticipate and therefore cannot respond to with appropriate investments. For this reason, the BMWK believes that these events can only be insufficiently covered by a capacity market or, in the worst case, not covered at all. This is because it aims to achieve an efficient level of security of supply that largely excludes rare or unforeseeable events. For this reason, the BMWK believes that the concept of a reserve alongside the capacity mechanism makes sense in order to prevent "blind spots". The reserve would supplement the efficient capacity mechanism by only reacting to unforeseeable events.

Box 9

The wholesale electricity market fulfils its coordinating function effectively and reliably via the merit order

Prices in the electricity market are determined by supply and demand. As part of the pricing process, the electricity generation units will be deployed on the basis of their variable production costs (merit order, i.e. supply curve). The price on the power exchange is then determined on the basis of the marginal costs of the last unit still required. Today, the last unit required is usually a power plant; whereas in future, loads or storage facilities are more frequently likely to be the marginal unit.

The price of the last, so-called marginal unit, which brings together supply and demand, determines the market price that all sellers receive and all buyers pay. If, for example, the marginal unit is a power plant, the price set by this power plant sets the market price for all, regardless of the individual marginal costs of the inframarginal power plants. This means that these price-setting marginal costs represent the market value of electricity in a particular delivery (quarter) hour.

This method, known as "marginal pricing", ensures that the most cost-effective generation units are deployed first and that demand is met with the most cost-effective supply that is available across Europe in this hour. This minimises the overall economic costs and creates a key prerequisite for low electricity prices.

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In addition to economic efficiency, pricing in the wholesale market using the merit order also ensures security of supply. This because only an undistorted price signal allows market players to make the right decisions regarding the deployment of their power plants and storage facilities, in addition to the temporary reduction of their consumption in times of market shortages, and ensures that electricity demand can be covered at short notice at all times in a uniform and liquid market.

Pricing on the wholesale electricity market using the merit order is thus the "conductor" that is necessary to create and orchestrate an internal market for electricity.

Markets with continuous trading, such as the futures markets or the intraday market, are based on the market value of electricity for a specific delivery (quarter) hour. Although the market participants on these markets could theoretically also try to buy or sell at other prices, there is no incentive for electricity buyers to purchase electricity above the market value of electricity and no incentive for electricity sellers to sell their electricity below the market value of electricity. In these markets as well, the electricity price is therefore set at the market value that emerges on the day-ahead market.

Box 10

The role of reserves in a future electricity market design

As a competitive approach, the current Energy-Only Market 2.0 (EOM 2.0) is inherently designed to achieve an efficient level of security of supply level. This means that market participants protect themselves against developments that are foreseeable and have a sufficiently high probability of occurrence by investing in capacity. Under EU law, capacity mechanisms – regardless of their further design – may only ensure an effective level of resource adequacy. However, when determining this effective level, very rare or unforeseeable extreme situations are not taken into account (e.g. exceptional cold spells, an above-average number of unavailable power plants due to fuel shortages or droughts, and combinations of these (multiple outages)). The triple crisis in 2022 with the loss of Russian gas supplies, the extensive outages of France's nuclear power plant fleet and a prolonged drought in parts of Europe, which led to power plant outages due to a lack of river cooling and reduced availability of pumped storage power plants, is a very good example.

To respond to such extreme situations, additional capacities may be useful and necessary as a possible measure. These will not be provided, however, either by a competitive electricity market such as EOM 2.0, or a capacity market.

It is nevertheless the duty of the state – and also stipulated by European law – to prepare measures to prevent and manage such unforeseen crisis situations. This is set out in the EU Risk Preparedness Regulation (European Union (2019)), which requires Member States to identify potential extreme events and develop suitable measures to prevent and manage such events in a risk preparedness plan.

One such measure is to maintain a reserve of controllable capacities. This will be held by the TSOs outside the market for extreme situations and will only be deployed in such rare or unforeseeable crisis situations. The reserve would supplement the effective capacity mechanism in order to avoid "blind spots". It should therefore focus on existing plants.

The discussion about "whether" is now becoming a discussion about "how"

The challenges around the introduction of capacity mechanisms as such are now shifting to the challenges of the design. The challenges of a capacity mechanism (new subsidy, risk of over-dimensioning and additional costs, in addition to prejudice against flexibility, innovation and smaller applications in the market) remain. They are now shifting to the design of the capacity mechanism, where they should be taken all the more into account.

The introduction of a capacity mechanism is a challenging task that involves a large number of parameterisation issues. Ultimately, a capacity mechanism assumes some of the risks to which market participants are currently exposed (such as forecasting future capacity requirements and market developments, and dealing with flexibilities). This leads to challenges that are generally associated with the introduction of a capacity mechanism (such as new payment flows that have to be refinanced, the risk of over-dimensioning, and prejudice against flexibilities) and which must be taken into account in the design. A crucial question, therefore, will be what answers the various options have for the design of a capacity mechanism to deal with these challenges, and how "susceptible to parametrisation" they are in each case.

The market development risk is a challenge for the design. The uncertainty investors face about the future development of the market (such as ramp-up flexibility) is at least partially alleviated with a capacity mechanism, since their investments receive financial support.

But these risks will then be transferred to the implementation and design of the capacity mechanism. Examples: How many heat pumps or electric cars will enter the system driven by market needs alone? To what extent and how quickly will demand flexibility be ramped up through smart meters and dynamic tariffs? What new business models, such as flex pooling provided by aggregators, will emerge?

A crucial question will be which design of the capacity mechanism has the most effective answer to these uncertainties and is the most adaptable and compatible for future developments.

3.2.3 Possible options for action for an investment framework for controllable capacities

The discussion about the options for a capacity mechanism can be condensed in the following options (Figure 13):

Figure 13: Options for financing controllable capacities

OPTION 1	OPTION 2	OPTION 3	OPTION 4
Capacity safeguarding mechanism through peak price hedging	Decentralised capacity market	Central capacity market	Combined capacity market

In order to assess the opportunities and challenges of the individual options, consideration may be given, for example, to:

- the extent to which the respective option can **effectively** guarantee **resource adequacy** by creating the right degree of planning security for the respective investment,
- the extent to which the respective option incentivises an **effective technology mix** that supports the integration of renewable energy sources,
- the extent to which the respective option provides the controllable capacities required to ensure resource adequacy **at low cost**,
- the **implementation and enforcement costs** for market participants that are associated with the respective options and how susceptible they are to incorrect parameterisation,
- the extent to which the respective option is **adaptable** and **able to cope** with the uncertainties of future developments,
- how **costs** are **refinanced**.

Box 11

The introduction and the implementation of capacity mechanisms is subject to a variety of requirements under EU law

Both the EU Internal Electricity Market Regulation and the guidelines on State aid for climate, environmental protection and energy contain various requirements that capacity mechanisms must fulfil. These include, among other things, that before a capacity mechanism is introduced, it must be demonstrated that the national security of supply standard will not be met without this mechanism. The introduction must also be accompanied by a comprehensive market reform plan.

There are also various requirements that must be met regarding the implementation of the mechanism, e.g. (1) technology-neutral and competitive procurement, including the integration of storage systems and demand response, (2) opening of cross-border markets for foreign capacities, (3) a maximum emissions cap of 550 grams of CO_2 /kWh, (4) a regulation on the conversion of natural gas-fired power plants to hydrogen, (5) repayment in the event of overproduction (claw-back) (see Box 2). The guidelines also stipulate, among other things, that the costs associated with the mechanism should be borne by those market participants that make the mechanism necessary.

In addition, a local component is also relevant for a German capacity mechanism that will provide an appropriate geographical distribution of new controllable capacities in Germany in order to avoid triggering new grid bottlenecks or additional cost-intensive grid expansion. Approaches for locational signals are dealt with in Chapter 3.3.

Option 1:
Capacity safeguarding mechanism through peak price hedging (CMP)

Explanation of the option:

- The capacity safeguarding mechanism through peak price hedging (CMP) builds on well-known hedging mechanisms of today's electricity markets and develops them further in a targeted manner.

- Suppliers and capacity operators are already hedging prices at an early stage via futures trading (see "hedging", Box 12). However, today's futures trading products only cover a largely constant electricity supply, but not short-term peaks in consumption. Suppliers would have to procure the latter at short notice at potentially very high prices on the short-term markets.

- The new EU Internal Electricity Market Regulation, therefore, requires suppliers in future to establish suitable hedging strategies, which can be based for example, on such financial hedging transactions (hedging obligation).

- The CMP would build on this new EU obligation and develop it into an extended hedging obligation. This would encourage suppliers to hedge their procurement volumes specifically against price peaks and thus for situations of acute shortage.

- This will create demand for corresponding hedging products on the futures market, which in turn will attract various providers of such products.

- It would make sense to require the balancing responsible parties (BRPs) specifically to implement the new EU obligation. They already maintain a virtual energy volume account and ultimately will also be required to implement the new EU hedging obligation, as they are responsible for procuring electricity and hedging prices and already have the data needed to implement the mechanism.

- Suppliers of such products would typically be operators of controllable capacities, especially peak load technologies, such as gas turbines or batteries. How the products are actually designed is left to the market. By selling these products, providers can secure their revenues and thus their investments better than they can today. Financial players such as banks could also be considered as providers, offering such a product as a form of price insurance.

- In a CMP, the amount of capacity allocated results from the actual electricity demand to be hedged, while the technology mix of controllable capacities is determined by individual decisions of the respective players required to implement the new EU obligation. This should ensure a high degree of adaptability and market efficiency.

Box 12

How does trading of power market futures work?

When trading power market futures, a supplier procures electricity from a producer with a lead time of one to three years over a predefined delivery period (usually a year, a quarter or a month). The amount of electricity procured remains constant over the entire delivery period. In this way, the supplier ensures that it can supply its end customers with the contractually agreed quantity and price.

The fulfilment of forward contracts is often on a financial basis, which means that no electricity is ultimately provided physically. Instead, the supplier of the product, such as a peakload power plant, for example, pays the supplier the difference between the current wholesale electricity price and a predefined price level if the wholesale electricity price rises above the predefined price level. In return, the buyer pays the supplier the purchase price for the product, which thus represents a form of insurance premium.

- To ensure that the mechanism works and actually generates additional revenues for the providers of controllable capacities, the BRPs must ensure that they are hedged against price peaks at all times. In the event of violations of the hedging obligation, penalties would be due. These penalties are not new and exist today in the case of unbalanced balancing groups if suppliers have not procured sufficient electricity on the market to supply their end customers. The necessary information could be generated, for example, by analysing trading transactions, which are recorded as standard on the basis of the EU REMIT regulation[17].

- In order to make locational signals possible through the instrument itself, it would probably be necessary to define regionally differentiated market segments for the hedging products, which would be used by suppliers based on their electricity sales in the respective regions.

- The costs for the hedging transactions would presumably be passed on by the BRPs to the suppliers, where they would in turn be included in the total costs of electricity procurement. It is difficult to estimate the costs in the case of the CMP, as the costs for the hedging products are not necessarily based on specific costs for controllable capacities.

Variation: combination with a minimum price for hedging products (CMP-Plus)

- If an even stronger hedging of revenues for operators of controllable capacities is politically desirable, a minimum price for specific hedging products could be introduced as an additional component. The minimum price would include a state price guarantee for the initial sale of a corresponding hedging product. This can take the form of an auction; if the achievable price is below the minimum price, then the state price guarantee will apply. The price guarantee will only apply at this time; there is no price guarantee if the hedging product is resold on the market at a later date.

- This guarantee is open to providers of hedging products who have their own controllable capacities (e.g. power plant operators, but not financial players).

17 European Union (2011)

- By launching the product on the market on a recurring basis (e.g. annually), it is also possible to secure revenues over the longer term for investments, for example.

- The processing and financing of the minimum price would be the task of a centralised body (e.g. transmission system operator (TSO), Federal Network Agency).

- If costs are incurred by the central body as a result of the minimum price, it would either pass these costs on to the BRPs or pass them on by means of a surcharge.

Opportunities of the CMP:

- The CMP provides market participants with considerable room for manoeuvre, as it is basically up to the market to decide which products are used to meet the hedging requirement and which technology options are best suited to meeting the demand for such products. It should therefore lead to an effective technology mix and use decentralised knowledge for this purpose.

- As a result of its market-based approach, the CMP is particularly well suited to responding to technological developments (type or cost of technologies) over time. It makes optimum use of decentralised local knowledge about technological developments and possible solutions, and therefore has a very high level of adaptability and the ability to keep up with energy transition developments.

- In addition, the CMP is likely to develop and use innovations (e.g. in futures market products, hedging strategies and technologies) from the market.

- In order to offer appropriate hedging products, market participants do not need to be pre-qualified by a central body or to assess how reliable their contribution to covering the residual peak load could be. The CMP is therefore particularly technology-neutral and has a particularly low susceptibility to parameterisation.

- The CMP should pass on the costs associated with the hedging directly to the end customer to the extent required by the market and thus ensure secure refinancing channels. No new state surcharges or similar are required, which in turn could turn out to be new obstacles to sector coupling or flexible behaviour on the consumption side.

- No skimming regulation would be necessary in the CMP. A certain amount of skimming is already a characteristic of hedging products against price peaks: Particularly high revenues (above the agreed hedging price) are passed on to the buyer of the hedging products, i.e. the BRPs, and can thus indirectly benefit the end customers.

- As a further development of the hedging obligation under European law, the CMP is likely to be free of state aid.

Challenges of the CMP:

One of the challenges of the CMP could be that hedging against price peaks can also be on a financial basis. For this reason, it is not certain to what extent this hedging is actually backed by a long-term contract with physical capacities. Without a physical backing, however, the provider of the hedging product would be taking a very high financial risk. He would have to pay the buyer of the hedging product the price difference between the actual electricity price at power exchanges and the predefined price level. This would create a strong incentive to hedge physically. In any case, however, the BRP has the additional security of receiving the electricity at the predefined price level in times of price peaks. The providers of controllable capacities benefit indirectly through higher electricity market revenues if the BRP procures electricity at the high electricity prices (financially secured).

- In addition, due to the short (one to two-year) term of the forward hedge, the instrument offers a lower degree of planning security, particularly for investors with a longer planning horizon.

- The continuous monitoring to determine whether market participants reliably fulfil their hedging obligations at all times is likely to be accompanied by a corresponding administrative and control effort, although this will be triggered in part at least by the hedging obligation under European law.

- In order to ensure that market participants comply with the hedging obligation in a legally compliant manner, it would be necessary to define the kind of price peaks centrally (number of hours, duration and price level if applicable) against which market participants should hedge. This parameterisation should have a corresponding influence on what the hedging products will ultimately look like and which market participants will be able to offer such products.

- While retaining the uniform German bidding zone for wholesale electricity trading, regional signals should only be feasible for physically deposited hedging transactions, not for financial transactions. The market for hedging products would have to be broken down into trading regions and it would be the physical location of an asset that determines to which trading region it belongs. As the concept also explicitly includes financial hedging transactions, regional management in the CMP appears to be very challenging.

Opportunities of the CMP-Plus:

- The approach could increase planning security for controllable capacities by guaranteeing them a minimum price for forward products over a longer period of time, even if this only covers part of the risk or investment costs. The minimum price is only applicable if there is actual physical capacity behind the contract.

Challenge for the CMP-Plus:

- The introduction of a minimum price would increase the effort required for parameterisation, as the central body would have to determine, among other things, how many market participants should benefit from the minimum price, for how long the minimum price should be granted, at what level, and at what risk/ investment share.

- The guarantee of the minimum price or, in the event of a payout, the minimum price itself must be financed.

- With the introduction of a minimum price, there would be additional design issues, such as who benefits from price hedging in the event of price peaks.

- Furthermore, it remains to be seen to what extent the introduction of a minimum price will change the assessment of the CMP under state aid law.

Option 2:
Decentralised capacity market (DCM)

Explanation of the option:

- In a decentralised capacity market (DCM), suppliers are responsible for hedging their electricity supplies to their electricity customers with capacity.

- This is similar to the current balancing group principle, according to which suppliers are already responsible for hedging their electricity supply in terms of volume ("MWh"). In the DCM, this hedging is amended by an obligation to hedge the underlying electricity supply with capacity ("MW"). This approach is referred to as "decentralised" because the responsibility for providing sufficient capacity is decentralised and lies with the market participants.

- Suppliers can fulfil their hedging obligation by (1) reducing their demand at peak load times (e.g. by means of an incentive model for the load flexibility of their customers) and (2) covering their remaining demand (contribution to the residual peak load at times of low wind and solar PV) with controllable capacity. All market options are available to them for this purpose. To make this easier for them, they can purchase certificates from operators of controllable capacities, i.e. power plants, storage facilities or demand response.

- As with the CMP, in this case the BRPs would appear to be suitable players, who will be required to provide evidence of their electricity supply being also hedged with corresponding capacity. The BRPs are already required to hedge their electricity supply and they have the best information available as to how high their individual contribution to the residual peak load, i.e. how high their electricity demand to be hedged, is. They can best assess the behaviour of their customers and new developments, and can therefore optimise their behaviour (purchase of certificates or self-fulfilment) accordingly. They are also ideally positioned to provide the appropriate incentives and individual electricity tariffs to shift their customers' consumption from peak load times to times with low electricity prices. This flexibilisation helps the energy transition to save costs.

- To ensure the security of supply, a central body (e.g. TSO) checks in advance whether the capacity operators authorised to issue certificates meet certain technical requirements (prequalification) and how reliable their contribution to covering the residual peak load is (de-rating).

- In a DCM, this means that the amount of available capacity is determined by the electricity demand to be covered and the technology mix of controllable capacities by individual decisions taken by the respective suppliers and market participants.

- A major factor is what penalties will be incurred if a supplier does not submit enough certificates. This is also currently the case if there are imbalances within the balancing groups. In this case, suppliers that do not submit enough certificates must pay a so-called imbalance settlement price.

- The individual contribution of a BRP to the residual peak load is determined ex post, i.e. after the end of the relevant year, based on measured production data.

Compared with ex ante determination, this approach prevents the BRPs from misjudging their certificate requirements in advance and purchasing too many/too few certificates. In addition, it increases the incentive to reduce the residual load through self-fulfilment (load avoidance) and avoids an extensive and uncertain estimate of the expected demand. At the same time, the example of France shows in practice that a purely ex-post determination of the individual contribution of a BRP can lead to fluctuating prices in the markets, which in turn complicates the planning basis for the providers of certificates. Mixed approaches should therefore also be further explored.[18]

- The DCM also needs a central body (e.g. TSO, Federal Network Agency) who, among other things, identifies and determines the times of the residual peak load in advance, carries out the prequalification of certificate providers, monitors compliance with the provision of certificates by the BRPs and determines what penalty is to be paid in the event that the BRP in question does not issue enough certificates.

- Similar to the EU emissions trading scheme, a trade register would be necessary to continuously record the certificates issued by providers, the trading of these certificates and the provision of these certificates by the BRPs.

- Similar to the CMP, it would also be possible in the DCM to set up regionally differentiated certificates (and thus regionally differentiated markets) in order to control new investments in capacities regionally. This would possibly reflect regionally different needs for (new) controllable capacities in the respective certificate prices.

- The costs for the certificates will be borne by the BRPs and are likely to be passed on by them to the respective end customers as part of the total costs of electricity procurement.

Opportunities:

- The DCM is very well suited to developing various flexibility options. This is important as demand response is the key to a successful energy transition and an efficient overall system (see Chapter 2), as it makes better use of periods of favourable electricity prices and thus reduces the costs of the capacity market.

- The DCM relies on the BRPs' own economic incentives and increases them with respect to the current electricity market. The BRPs are also likely to have an interest in developing small-scale, decentralised flexibility options (e-mobility, heat pumps, home storage), as they can reduce their contribution to the residual peak load and have to purchase fewer certificates.

- For this reason, the DCM is also very much open to innovation, both in terms of new technologies and new business areas such as the aggregation of demand response. To the extent that flexibility is unlocked directly by the BRPs in order to reduce their own certificate requirements, no prequalification of the capacities by a central body is required and these options can therefore not be forced out of the solution space by excessive regulatory requirements. This means that the DCM can contribute to an optimised back-up technology mix.

- The DCM is a "breathing" mechanism that flexibly readjusts the demand for capacities when evidence suggests there will be a higher or lower

18 In order to counter this risk, the BRPs could be required to purchase a portion of their expected demand for certificates before the expiry date of the delivery year (in several stages if necessary).

demand for capacities (e.g. due to higher residual loads as a result of economic effects). This readjustment takes place on the basis of a decision taken by the BRPs (self-fulfilment/certificate acquisition). Overall, it is characterised by a very high degree of adaptability and the ability to keep up with energy transition developments.

- The DCM makes optimum use of local decentralised knowledge to estimate the demand (load uncertainty) and the technological possibilities. Decentralised knowledge is particularly important in view of the load uncertainty with regard to future development.

- The susceptibility to parameterisation is higher than with the CMP (without a minimum price), as mismanagement can occur through pre-qualification and penalties, but is lower than with the central capacity market (greater risk of over-dimensioning and preference for known technologies by the central body).

- No new state funding is necessary and no new surcharge is required. This means that there are no new obstacles to sector coupling or flexible consumer behaviour.

- The problem of repayment (see Box 2) does not arise.

Challenges:

- Only certificates with relatively short contract durations (essentially one to three years) are traded in the DCM. As in today's futures market, BRPs can only engage in the procurement of certificates as far into the future as this corresponds to their own electricity sales to end customers (matching maturities). The short durations could therefore pose a challenge for investors in controllable capacities with longer-term refinancing horizons (e.g. new power plants), as the desired long-term planning security may not be adequate (see above, timeline mismatch).

- Consequently, the refinancing costs for new capacities in the DCM are likely to be higher than in the centralised capacity market, for example, as higher uncertainties in refinancing are reflected in the form of higher risk premiums for debt financing.

- The requirements and controls are likely to be accompanied by a corresponding administrative and control effort (e.g. annual control of the fulfilment of obligations/certificate submission for all suppliers/BRPs, register management).

- In addition, the central body must balance out the penalties in a way that will ensure that neither large amounts of capacity (over-dimensioning, which leads to unnecessary additional costs) are ineffectively incentivised, nor under-dimensioning results (insufficient security of supply). However, many of these tasks are already known in principle in today's balancing group system and could be used as a basis.

Option 3:
Central capacity market (CeCM)

Explanation of the option:

- In a central capacity market (CeCM), a central body determines the demand for controllable capacities and tenders them completely (i.e. existing and new plants) in auctions.
- Providers of controllable capacities are basically – as in the DCM – operators of controllable capacities, i.e. power plants, storage facilities or demand response.
- A state-authorised body, such as the TSOs or the Federal Network Agency, acts as the tendering body and thus as a quasi-purchaser of controllable capacities.
- This central body also checks in advance in the CeCM as to whether the capacities fulfil specific technical requirements and how reliable their contribution is to covering the residual peak load (prequalification).
- Successful bidders receive a capacity payment (euros/MW per year). In return, they undertake to keep their capacity technically available.
- In a CeCM, the amount of available capacity and the technology mix of controllable capacities are therefore primarily determined by regulatory, centralised decisions based on a centralised forecast that has been carried out in advance.
- The central body has an important function as it determines the capacity requirements, typically on the basis of a resource adequacy assessment and the information they have available on so-called demand-dimensioning situations in the electricity system. It can specify different contract durations in order to reflect the different financing horizons (e.g. short-term for existing plants, long-term for new power plants) and possibly also specify products with different technical requirements. Furthermore, the central body also specifies the tendering rules and, among other things, control and sanction mechanisms.
- Locational signals could be implemented in the CeCM in the central auctions in the form of regional quotas or bonus/malus regulations and thus make regional signals of investments possible (see also the “Locational signals” field of action, Chapter 3.3).
- The costs of the CeCM depend largely on its design. In a CeCM, there is a tendency for bids to be made at a standardised market clearing price. This leads to comparatively high overall costs. Market segmentation by means of separate auctions, different products or specific price caps in principle could reduce the overall costs. As a result of efforts to find alternatives, however, the cost-reducing effect of market segmentation could be less effective and decline over time. The costs would have to be borne in the form of a state surcharge, as the requirements of the European Commission’s current guidelines on State aid for climate, environmental protection and energy require financing by those for whom a capacity mechanism was introduced.[19]

19 European Union (2022), marginal 367

Opportunities:

- The CeCM primarily offers the benefit of very high investment security.

- The capacities required to guarantee resource adequacy are determined and procured centrally. This would create a high level of security and trust with regard to resource adequacy.

- As a rule, there are different technologies and providers competing in an auction, which can contribute to cost efficiency.

- In the CeCM, capacity payments can vary in length depending on the product. Longer contract durations lead to a stable and predictable revenue stream. This specifically addresses the problem of timeline mismatches for investments that are particularly capital-intensive. It should also reduce capital costs.

- As only the providers of controllable capacities that have submitted successful bids have to be examined in the CeCM, there is no need to check the suppliers, unlike in the DCM. However, the prequalification requirements are higher, as all technologies must be classified and assessed for their contribution to resource adequacy.

Challenges:

- The CeCM generally faces challenges when integrating demand response and, where applicable, storage facilities. Capacity providers may only participate in the tender procedures following successful pre-qualification. This presents a regulatory and bureaucratic obstacle, particularly for new technologies or smaller scale flexibilities, such as e-mobility or heat pumps, as it is challenging to classify the large volume of demand response and new, innovative solutions and to prequalify them in terms of their contribution to the security of supply. In addition, the CeCM tends to measure the contribution of demand response and storage to covering peak load in a particularly risk-averse manner and therefore to “de-rate” them more severely. As a result, these options tend to have less chance of success in the tenders. The consequence of this is that flexibility is not only not taken into account, but its business case will deteriorate as other controllable capacities enter the market via the CeCM.

- For the same reason, the CeCM is generally less open to innovation for new business models or technologies. Due to their novel nature, it is unlikely that these can be easily mapped in the central, standardised specifications and processes (for example, in technical prequalification or in the assessment of the security of supply contribution).

- Dimensioning by a central, generally risk-averse player in the CeCM carries the risk that more capacity will be procured than necessary, which would be accompanied by the relevant additional costs (over-dimensioning).

- It is more difficult for the CeCM to respond to uncertainties in the development of the electricity system. The demand for controllable capacity is centrally forecasted and fixed several years in advance. It therefore tends to be less adaptable and able to keep up with future developments than the CMP or DCM, which in turn is likely to be reflected in higher dimensioning.

- When setting parameters, the CeCM requires various assumptions and modelling (e.g. for dimensioning, possible product differentiation), which are likely to be associated with a significant susceptibility to errors – as well as a tendency to over-dimensioning in the case of a central body with a tendency towards risk aversion.

- In the CeCM, the capacity payment is determined by auction and these costs must be refinanced. Financing would have to take place via a new surcharge, which could create new hurdles for sector coupling and flexibility.

Option 4:
Combined capacity market (CoCM)

Explanation of the option:

- A combined capacity market (CoCM) is a combination of a DCM and a CeCM. Details of a CoCM can be designed in different ways. One model has been proposed by the German Monopolies Commission and was presented in the PKNS.[20] The option presented in this paper uses elements of the Monopolies Commission's proposal, but also draws on the concepts of the DCM and the CeCM. The aim is to combine the benefits of both approaches: investment security for long-term investments on the one hand (through a centralised component) and openness to innovation, adaptability and an optimum technology mix through the integration of decentralised local knowledge on the other (through a decentralised component).

- *Central component*: a central body tenders new controllable capacities to be built with longer-term refinancing periods, for which there is a problem of timeline mismatch (as a rule, the market has a three-year maximum hedging horizon, but capital-intensive investments require 15-year refinancing horizons). These investments are generally associated with particularly high capital expenditure and long refinancing periods and therefore require a higher degree of investment security. Successful bidders receive an annual capacity payment for making the capacity available over the entire contract duration.

  - *Decentralised component*: this covers new investments and existing operators of capacities to cover the load. As in the DCM, it is the task of the BRPs to secure their contribution to the residual peak load with capacities. This can be done by means of self-fulfilment or by acquiring corresponding certificates.

- Capacity providers in the central auction would be operators of new controllable capacities with a long-term refinancing horizon. In contrast, operators of new and existing installations with refinancing horizons that are not as long participate in the certificate market. The BRPs act as purchasers of certificates.

- The interaction between the decentralised and central component must be carefully designed. Various approaches are conceivable. The contracts awarded for new capacities in the central tendering process could then be fed into the decentralised certificate system as certificates and acquired by the BRPs as evidence of capacity (trading model). Alternatively, the obligations of the BRPs could be reduced by precisely this amount of capacity, so that the BRPs would need to provide correspondingly fewer certificates (discount model).

- In the CoCM, the central body assumes responsibility for the partial dimensioning of the demand for new controllable capacities and puts this out to tender by auction. To do this, the central body must estimate the demand for new controllable capacities in advance. Furthermore, it monitors the fulfilment of the BRPs' obligations, in addition to the decentralised certificate trading (register management) for the decentralised component. The prequalification (for new installations in the invitations to tender and for providers of certificate), in addition to control and sanctioning tasks, must be defined and implemented for both components.

20 Monopolies Commission (2023)

- The costs for decentralised hedging should be passed on via the procurement costs of the BRPs, which would mean that no new surcharge is created. The costs of the central component would in turn have to be passed on by means of a surcharge, but this would be lower than in the purely central capacity market, as only a portion of the capacity demand (namely the demand for new build capacity, particularly with a long-term refinancing horizon) is put out to tender centrally. In addition, the certificates for the awarded capacities would be placed on the market in the decentralised segment. Any revenues generated there would be offset in the calculation of the surcharge, which would reduce this further. As a result, the surcharge is significantly lower than in the central capacity market and, depending on how it is designed, can be quite small.

Opportunities:

- The CoCM combines the benefits of the CeCM and the DCM.

- The capacity contracts with longer duration that are put out to tender centrally provide a stable and predictable, long-term revenue stream for new controllable capacities with longer refinancing horizons.

- The CoCM makes use of the DCM's openness to technology and innovation, its high incentive for demand response and the integration of storage facilities and innovative solutions, in addition to its strength to achieve an optimal technology mix by applying local decentralised intelligence.

- As a result, it is particularly technology-neutral.

- It makes use in particular of the ability of the DCM to adapt to future developments in the energy transition and benefits from the valuable decentralised knowledge that is available in order to respond to this load uncertainty.

- The risks of over-dimensioning are lower in the CoCM than in the CeCM, as the volumes put out to tender centrally make up only a small segment compared with the total capacity addressed in the CoCM.

- In the CoCM, providers with a long refinancing horizon can choose whether to bid in the central tendering process and accept the consequences of being subject to the clawback mechanism – or whether to hedge the revenues via the DCM with the benefit of probably not being covered by the clawback mechanism.

- In the CoCM, only the costs associated with the central component would be refinanced through a surcharge. The surcharge as a result would be significantly lower than the value of a central capacity market. An additional cost-reducing effect results from the fact that the certificates for the tendered capacities in the decentralised market generate revenues that will be offset against the calculation of the surcharge. Furthermore, it is possible that certificate prices could be quoted in the decentralised part that are significantly lower than those of an open-cycle gas turbine. As a result of the reduced surcharge, new obstacles to sector coupling and load flexibility are likely to be significantly limited by comparison with a pure CeCM.

Challenges:

- Much like the DCM, the challenge of the CoCM is that, in addition to the requirements and controls for providers of capacities, the same is also needed on the demand side.

- Furthermore, the distinction or interrelationship between the central and decentralised components also needs to be parameterised. As a result of there being two segments, the introduction of a CoCM is initially likely to involve increased cost and effort for parameterisation and implementation, which will be reduced, however, once the CoCM has been set up.

Figure 14 provides an overview of the opportunities and challenges resulting from the above assessments of the individual options for designing a capacity mechanism.

Figure 14: Overview of the opportunities and challenges of the main options for capacity mechanisms

Criteria	CMP		DCM	CeCM	CoCM
Resource adequacy	+		+	++	++
Investment security (compared with EOM 2.0)	+		+	++	++
Openness to technology	++		++	-	++
Adaptability/energy transition compatibility with new developments	++		++	-	++
Complexity/administrative effort	-		~	+	~
Regionalisation	-		~	~	~
Direct costs	+		+	~	+
Incentives for cost effectiveness	++		++	-	+
Refinancing	+	~*	+	-	+

Rating: ++ = Very good; + = Good; ~ = Neutral; - = Poor; * = CMP variant with minimum price

Source: Own diagram

Summary of the investment framework for controllable capacities field of action

- The existing electricity market should be supplemented by an additional investment framework for controllable capacities. Long-term investment security is particularly important for capital-intensive investments that have a longer refinancing horizon than the market guarantees (problem of timeline mismatch).

- In its Initiative for Growth published at the beginning of July, the Federal Government confirmed its intention to introduce a technology-neutral capacity mechanism that will enter into operation by 2028 and will enable competition between run-of-river power plants, pumped storage plants, battery storage, bioenergy plants, other back-up power plants as well as storage and demand response. The options presented in this paper and the subsequent consultation process will form the basis for the decision planned by the Federal Government to introduce a capacity mechanism.

- A capacity mechanism will supplement the wholesale market, which will retain its coordinating function on the basis of the merit order in order to manage dispatch effectively. Revenues from the electricity market will remain an important refinancing factor.

- The capacity mechanism is intended to give providers an additional revenue stream for the provision of controllable capacities in order to secure investments during the uncertain development of the energy system transformation.

- The relevant aspects in the discussion about the “whether” of a capacity market are now shifting to the “how” of its design.

- A capacity mechanism that is compatible with the energy transition should support a technology mix of power plants, storage facilities and demand response that is effective and ensures the security of supply. It should be based on a competitive approach, be open to innovation and be able to connect with future developments. It should be able to adapt well to future energy transition developments and technological progress, and thus guarantee resource adequacy in a cost-effective manner.

- A central capacity market provides a high level of investment security. However, it is less effective at unlocking demand response or new, innovative solutions, since all participants must be pre-qualified and it is a challenging task to classify the large volumes of demand response and new, innovative solutions, and then to pre-qualify them in terms of their contribution to resource adequacy. As a result, flexibility is not only not taken into account, but its business case deteriorates as other controllable capacities enter the market via the CeCM. In addition, the CeCM is less adaptable to new developments and previous CeCMs have not yet found an answer to the problem of load uncertainty, i.e. the fact that the future development of the electricity market is difficult to predict. The CeCM is accompanied by the repayment of high electricity market revenues and a new state surcharge, which could mean new challenges for sector coupling and demand response.

→

- A decentralised capacity mechanism or a capacity safeguarding mechanism through peak price hedging, as a result of the shorter hedging contracts, offer less investment security for long-term investments. However, they are more open to innovation and develop flexibility and smaller market players better. In addition, the DCM provides additional incentives for flexibility due to the high incentive for load avoidance in times of high electricity prices (self-fulfilment). They are "breathing" and adaptable mechanisms, are able to adjust to load uncertainty and future developments, in addition to new innovations, and exploit the valuable decentralised knowledge for this purpose.

- From the BMWK's current perspective, a combined capacity market would therefore appear to be the ideal way of ensuring resource adequacy in a reliable and cost-effective manner. It combines the benefits of the CeCM and the DCM/CMP, as it is able to address what is frequently regarded as the "new world" in an electricity system characterised by renewable energy sources and flexibility particularly well. On the one hand, in the case of investments with a long refinancing horizon that are particularly capital-intensive and for which there is a problem of timeline mismatches, the CoCM provides focused long-term investment security by means of central tenders with long contract duration. On the other hand, flexible purchasers, storage facilities and innovations are involved in an optimum way, making it a very technology-neutral design option. It provides the best way of addressing uncertainties in forecasting the future and the complex changes that take place "as we move forward" by applying the decentralised knowledge of local energy suppliers and responsible parties. This combination significantly reduces the costs of the central component to be allocated by means of a surcharge and creates no new obstacles for sector coupling and demand response.

Key questions for the consultation:

1. How do you assess the necessity of the capacity mechanism's adaptability and its ability to keep up with future developments?

2. How do you assess the challenge in the CeCM of taking into account the contribution of new technologies and demand response in particular, as well as the risk of over-dimensioning?

3. What total costs do you expect for the various options, especially for the CeCM and the CoCM?

4. In your view, how significant are the effects on storage facilities and demand response due to the repayments required under European law, which are particularly relevant in the CeCM?

5. How do you evaluate the synthesis of CeCM and DCM in the combined CoCM in terms of the opportunities and challenges?

6. Would, in your opinion, a combination of CeCM and CMP also be conceivable?

3.3 Locational signals

3.3.1 Dealing with grid bottlenecks as we move forward to a decarbonised electricity system

The subject of locational signals was discussed particularly intensively and controversially in the PKNS. The stakeholders of the PKNS agreed that some form of locational signals or local control will be necessary in the future electricity market design.

Firstly, it should be made clear that the BMWK is committed to maintaining the single German-Luxembourg bidding zone. The challenges of congestion management and grid operation will increase in the future, however. In order to limit the extent of congestion situations so that they can continue to be resolved in a single bidding zone through redispatch and grid expansion, the electricity market design must be supplemented by a locality dimension.

Energy transition requires new interaction between market and grid

The market *and* grid guarantee a secure and efficient supply of electricity. In the past, power plants in most cases were built close to the load centres, i.e. in southern and western Germany. As a result of the energy transition, there has been a fundamental change in where we generate electricity. The expansion of renewable energy sources is taking place primarily where the best yield from wind and sunshine can be achieved. Wind power as the most important source of electricity will be generated, therefore, increasingly in northern and eastern Germany.

To ensure this can succeed, the grid is of crucial importance: the transmission grid transports electricity over long distances as the main artery, so to speak, while the fine veins of the distribution grid then deliver it to the local electricity consumers and collect locally generated renewable electricity. The transmission grid in Germany has a length of some 37,000 kilometres and the distribution grid, which supplies private households and companies, has a total length of more than 1.2 million kilometres (low voltage).

European energy transition and grid expansion go hand in hand

The energy transition is a pan-European project. Europe is determined to increase the share of renewable energy sources in gross final energy consumption to 45 per cent by 2030. This corresponds to around 70 to 80 per cent of renewable energy sources in the electricity sector across Europe. By 2040, this share is expected to rise to over 90 per cent. In order for this to be achieved, electricity must be transported from windswept Scandinavia, the North and Baltic Sea region, the sunny Mediterranean region and from energy storage systems, such as hydropower in Norway and the Alpine region to the rest of Europe. This means that generation, load and storage centres will have to be networked much more intensively.

As a result of its central location in Europe, Germany will become an increasingly important hub for electricity transport, but also for electricity trading in the European internal market. Germany is already benefiting from wind power imports from Scandinavia or electricity balancing in the European internal market when there is not enough wind or solar power available here. This role and position, however, also come with a special responsibility for European integration. Grid congestion situations in Germany, for example, must not be resolved at the expense of electricity from outside the country. The following applies: 70 per cent of the line capacity that is relevant for cross-border trade will have to be reserved for cross-border trade flows. This will create additional challenges in terms of grid expansion and redispatch.

The European electricity market model is based on a zonal approach – together with Luxembourg, Germany has a unified electricity bidding zone at its disposal in which a single electricity price applies. Electricity can be traded at will within a bidding zone – without having to be concerned about how the electricity is transported around the grid. As a result, the exchange or wholesale price for electricity within the bidding zone is the same every hour or every quarter of an hour. There are no restrictions on trade. This model relies on a "copper plate assumption" in order to make the most liquid trading possible. Grid congestion is to be solved by grid congestion management measures, in particular with so-called redispatch, by the grid operators.

A large, unified bidding zone with many market participants ensures high liquidity in electricity trading. A unified market area means that the most cost-effective generation technologies prevail within Germany, regardless of location and grid situation. This lowers electricity procurement costs. A large market area also makes it possible to make greater use of geographical equalisation effects in generation and consumption, for example, because demand is not the same everywhere or the wind does not blow uniformly. High market liquidity is also becoming increasingly important in order to absorb steep ramps in the feed-in of solar PV electricity, for example. On the other hand, however, there are redispatch costs to transport the market result to consumers via the grid.

The idea of a single European market with as few trading restrictions as possible would correspond to a Europe-wide copper plate, but this is not physically feasible. For this reason, and because this has grown historically, grid bottlenecks between the bidding zones have to be effectively managed, i.e. cross-border trading capacities have to be allocated.

Grid expansion and redispatch

Redispatch is the answer, at least temporarily, in order to keep congestion reliably manageable – but the challenges are increasing. To transport electricity trading transactions via the grid physically as well, grid operators use redispatch when necessary. Redispatch refers to interventions by grid operators that instruct generation plants to increase or reduce plant deployment as required. This prevents grid overloads and ensures that the grid is operated safely and stably (see Box 13). Electricity customers pay the costs for these measures via the grid fees. The recent significant increase in redispatch measures (Figure 15) is also increasingly posing an operational challenge for the TSOs.

Box 13

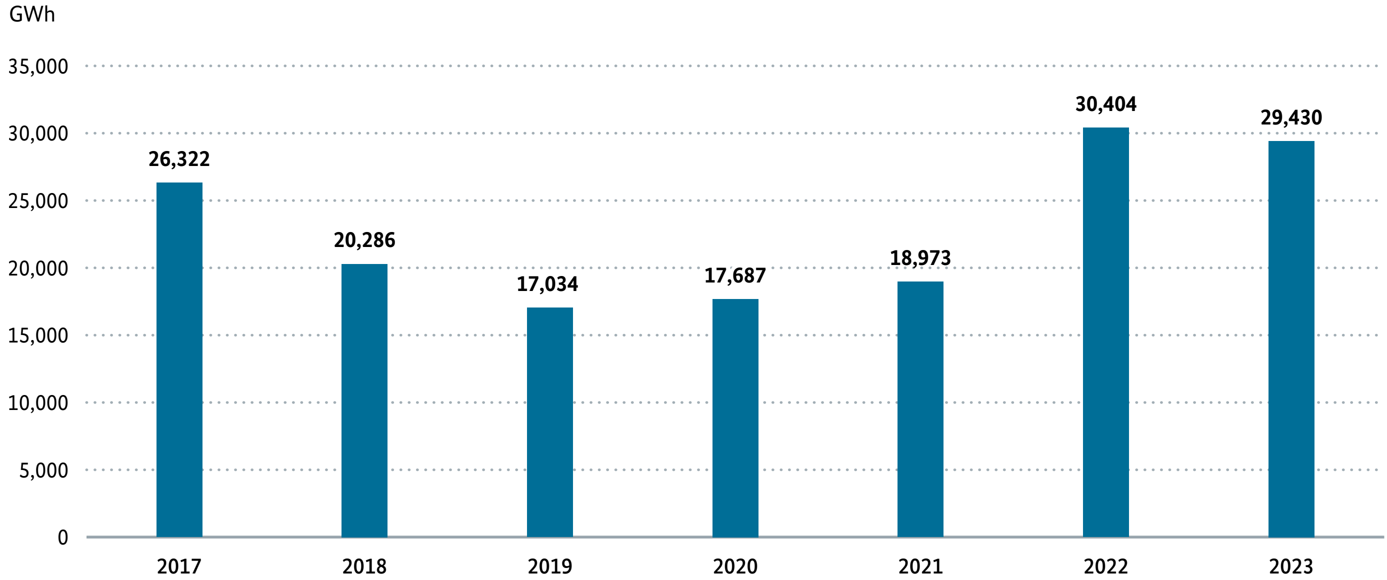
How are grid bottlenecks resolved?

- The grid operators (especially the TSOs) use grid congestion management to prevent grid congestion when necessary and thus to be able to operate the grid safely and stably.
- This is usually done by means of redispatch: if a bottleneck is imminent at a certain point in the grid, the grid operators instruct generators upstream of the bottleneck to reduce their feed-in – while generators downstream of the bottleneck have to increase their feed-in. In this way, a load flow is generated that counteracts the bottleneck; overall, the amount of electricity in the system remains the same, it is simply distributed locally in a different way. This typically happens at times of high renewable energy generation.
- Plant operators are compensated for these enforced plan changes, and they in turn have to assign revenues to the TSOs. Any remaining costs are then passed on to electricity consumers via the grid fees. This incentive-neutral principle is important to ensure that electricity trading is not distorted and grid congestion does not become a business model for a few players close to the congestion point.
- For some years now, the market generation capacities "behind" the bottleneck, i.e. in the southern part of Germany, have no longer been sufficient in some situations. The grid reserve holds power plants in reserve outside the market, which the TSOs can also use to ramp up if necessary. The intensity and frequency of these measures has increased significantly in recent years.
- As part of Regional Operational Security Coordination (ROSC), there will also be cross-border redispatch at European level in future. This will increase the effectiveness of redispatch procurement and further contribute to system security, but will not be active until 2026 at the earliest due to a complex, delayed implementation.
- In 2023, the total sum of redispatch measures amounted to 29.4 TWh, i.e. measures to increase and reduce the generation of market and grid reserve power plants to overcome grid bottlenecks. Wind generation was curtailed most frequently (around 9.7 TWh). Overall, however, 97 per cent of electricity from renewable energy sources was transported to consumers. In 2023, the costs for redispatch amounted to around 3.1 billion euros.

Grid expansion, digitisation and grid optimisation are the structural answers to reducing bottlenecks. As a result of the further expansion of renewable energy sources, rising electricity consumption and increasing European trade, the demands on the grids are increasing significantly and thus the need for grid expansion in the transmission and distribution grid.

The structural answer is grid expansion. Only in this way will it be possible to distribute and use affordable renewable electricity throughout Europe. To this end, several thousand kilometres of power lines are being converted and expanded in Germany. The grid expansion plans already enshrined in law at the transmission grid level amount to over 13,000 kilometres. Of these, around 2,300 kilometres are in operation and a

Figure 15: Redispatch from power plants on the market, grid reserve, feed-in management and adjustment measures, less countertrading (for comparability purposes, the quantities of the previous feed-in management are included)



Source: Federal Network Agency based on SMARD (2024 a)

further 2,900 kilometres have been approved or are already under construction. The remaining projects are at various planning and approval stages. The current 2023 – 2037/2045 grid development plan also shows an additional expansion requirement of around 7,300 kilometres in the transmission grid.[21]

This will require an enormous effort on the part of all those involved. In this legislative period, the Federal Government has achieved extensive measures to speed up the approval procedures at national and European level. These are already showing success. In 2023, four times as many power line kilometres were approved as in 2021, and this year it will be almost twice as many again. The number of power line kilometres under construction has also doubled in 2023 compared with 2021; this year, the BMWK expects construction to start on a record 1,500 kilometres (five times as many as in 2021).

In addition, it will be possible to use the existing grids more effectively, which will further increase grid capacity. One example of this is weather-dependent overhead line operation, in which the maximum possible load on the lines is determined on the basis of the current ambient temperature and weather conditions. Since 2023, the TSOs have been able to make extensive use of this instrument under Sections 49 a and 49 b of the Energy Industry Act. In addition, the use of high-temperature conductor cables in the existing grid can leverage further potential. Technologies used in the grid, such as phase-shifting transformers, can control the flow of electricity, distribute it uniformly and thus achieve an increase in electricity transport overall.

21 50Hertz Transmission GmbH, Amprion GmbH, TenneT TSO GmbH, TransnetBW GmbH (2023) und Bundesnetzagentur (2024 b)

In future, technological developments and innovative operational management concepts offer further optimisation potential that goes beyond the current state of the art. For example, so-called grid booster pilot facilities will go into operation as of 2025 and will be used to trial and introduce reactive response management, i.e. the higher utilisation of individual grid elements based on transmission demand.

A climate-neutral energy system in Germany and Europe is only possible with additional grid expansion, supported by grid optimisation. Germany is also making an important contribution to European integration in this area.

However, from an economic and acceptance perspective, it makes no sense to expand the transmission or distribution grid "down to the last kilowatt" (such as the highest generation peak). Grid expansion in the grid development plan is therefore not designed for a completely congestion-free grid. In the distribution grid in particular, to which the majority of new energy transition plants will be connected, digitisation and the optimised use of the grid infrastructure are decisive factors.

3.3.2 Role and importance of locational signals

Challenges will increase with increasing electrification

In the future electricity market, it will become increasingly important when and where we generate and consume electricity, and how this is coordinated with the grid. With an increasing number of flexible, decentralised electricity consumers, it is becoming increasingly important, that their behaviour and their location are in line with the grid situation. As grid expansion takes time and is not feasible right down to the last kilowatt hour, it is becoming increasingly important for market players to take the grid situation into account in their decisions and optimise their behaviour accordingly.

A large number of new flexible consumers will enter the system in the course of sector coupling. If they all follow the low electricity price signal and the grid congestion situation has no influence on their deployment decisions, this will present the overall system with very significant challenges.

This development therefore places new demands on the interaction between the market and the grid. For many new flexible consumers, such as electric cars or heat pumps, which are used close to the point of consumption, the main issue is a grid-compatible deployment decision. For other new consumers that do not necessarily have to be used close to the point of consumption, such as electrolysers in particular, it is primarily a question of siting.

Regional signals are key for new large-scale electricity consumers such as electrolysers. From a system perspective, new additional large-scale electricity consumers such as electrolysers in particular should be located where they relieve existing grid bottlenecks or at least don't make them worse. From a systemic perspective, electrolysers should therefore be sited primarily in areas close to renewable energy expansion regions, i.e. particularly in Germany's windy north. Ideally, they would then also be operated at such locations in a way that relieves the grid and benefits the system.

Electrolysers would thus make a very important contribution to a cost-effective energy transition and industrial competitiveness. They could use electricity in times of strong winds that would otherwise have to be curtailed in the north. The hydrogen could be stored in the caverns in northern Germany and transported to the south via the hydrogen network. This would be much more efficient than transporting the electricity to the south and producing hydrogen there with conversion losses. A hydrogen pipeline can transport approximately 10 times more energy than a power line. For the planning of the electricity grids in the grid development plan, new electrolysers are already assumed to be located predominantly in northern Germany. If significantly more electrolysers than previously planned are built in southern Germany, this could confront the overall system, grid expansion and the unified bidding zone with an almost impossible task if no further measures are taken.

However, in order to pave the way for siting decisions and operating modes that make systemic sense, it is essential that infrastructures such as hydrogen pipelines and hydrogen storage facilities are built that will benefit the system. The Federal Government will gradually implement the hydrogen core network from 2025 to 2032, followed by the further expansion of hydrogen networks.

A form of locational signals is necessary

Locational signals will therefore also be part of the answer in the future electricity market design. Since it makes no sense to expand the grid “down to the last kilowatt”, and yet at the same time more and more new flexible consumers and storage systems are being added to the system, the overall system will also require some form of locational signals. The stakeholders at the PKNS agreed on this.

A locational signal is an incentive that relieves the transmission or distribution grid, i.e. makes the limited capacity of the grids visible to players in the electricity system (for example by means of price signals, but also by means of other mechanisms). This can take place at the grid connection stage, for example, by means of a fee or a reduction in funding for generation facilities that are located in grid regions that already have scarce connection capacity, as is the case today with the so-called building cost subsidy. Put simply, locational signals create geographically and temporally differentiated smart incentives to consume electricity when and where there is a lot of green electricity in the system. Economists say that locational signals have the function of indicating to what extent electricity is in short supply at a location or in abundance, i.e. they also reflect the grid situation.

Locational signals – in contrast to regulatory measures – set incentives, so that market players optimise their behaviour voluntarily and according to their individual preferences. At the same time, this can result in positive benefits for the overall system, in particular by reducing the burden on the electricity grids.

Depending on the approach, locational signals can provide the necessary incentives for siting decisions and/or plant deployment. Locational signals can arise both from the electricity market, i.e. in the form of regionally more finely-resolved electricity prices, as well as via local elements in grid fees, funding measures or other mechanisms. There are two dimensions regarding the effects they can have:

1. Setting **investment/siting incentives** in such a way that, where possible, generation and loads are increasingly located in areas that benefit the grid: additional electricity generation capacities in regions with high electricity demand, additional loads in regions with lots of renewable electricity. Technologies differ in terms of their relocatability – electrolysers can be located in the north (combined with the hydrogen grid and storage facilities), whereas existing industrial processes or heat pumps/electromobility by contrast are virtually unable to do so, as they are tied to a specific location.

2. Setting **dispatch and consumption incentives** in such a way that the deployment or consumption decision takes local conditions, in particular the grid situation, into account: more electricity consumption at times of high local renewable electricity generation, less consumption and more deployment of plants at times of lower local renewable electricity generation.

Triple benefits of locational signals – but also challenges that need to be addressed. Locational signals can have a triple benefit: (1) The grid can be relieved, which supports reliable grid operation. (2) Greater local use of electricity increases system efficiency and can reduce redispatch costs and thus grid fees. (3) Local electricity consumers can respond more intelligently to the local grid situation and also benefit from cheaper electricity as a result.

Depending on the design and kind of locational signals and the regional impact, however, they can also lead to considerable political challenges in the areas of distributive justice, competitiveness and investment security. For a transitional period at least, the question of appropriate compensation instruments could therefore arise.

Locational signals will not replace the planned grid expansion. A triad will be required in future: efficient and secure redispatch, also across borders, at least as a short-term and transitional measure, the significant acceleration of grid expansion and locational signals that incentivize the grid-compatible behaviour of producers, consumers and storage facilities.

Box 14

No-regret measure: redispatch action package for greater reliability, efficiency and performance

Redispatch in Germany is a complex calculation, coordination and communication process between grid operators and generation plants. It begins a week before "real time" on the basis of forecasts. The deployment and call-off planning for the generation plants is continuously readjusted until the last moment. Regardless of which locational signals in future will be set how and where, redispatch will continue to be a necessary pillar. This process must therefore run smoothly in order to operate the electricity system reliably and cost-effectively in the future. With the increasing number of renewable energy plants and the decreasing number of large power plants in southern Germany, operational redispatch will also face numerous new challenges. These will have to be met with a redispatch action package that must include a package of measures designed to tackle these complex and new challenges.

The introduction of the so-called "Redispatch 2.0" should already be enough to increase the efficiency of operations and the redispatch potential at the same time by including smaller systems. In practice, however, there are major obstacles to implementation, especially in the distribution grids. The task must therefore be to move ahead rapidly with the systematic digitisation and standardisation of grids and plants.

At transmission grid level, the problem of a lack of ramp-up capacities south of the bottlenecks is already apparent in some cases. To this end, existing reserves must be made future-proof, the European coordination of cross-border redispatch must be implemented promptly and, finally, available loads should also be included in redispatch in an appropriate manner (see Option 3).

3.3.3 Possible options for action for locational signals

The following three options for action are considered separately for locational signals, which could also be implemented cumulatively (Figure 16).

Figure 16: Options for action for locational signals

OPTION 1	OPTION 2	OPTION 3
Temporally/regionally differentiated grid fees	Regional signals in funding programmes	Demand response in congestion management

Figure 17 categorises the measures presented in this paper with regard to these incentive effects: which measure sets for which technologies local incentives for investments and for consumption/dispatch that benefit the system.

Figure 17: Effect of various local instruments on investment decisions and deployment/consumption

	Generation		Demand response			Storage
	Wind/PV	Controllable generation	Electrolysers	Industrial generation	Household	Storage
Dispatch			Demand response in congestion management			
				Temporally/regionally differentiated grid fees		
Investment				Temporally/regionally differentiated grid fees		
	Regional signals in funding programmes					

Option 1: Temporally/regionally differentiated grid fees

Explanation of the option for action:

- Grid fees are becoming an increasingly important component of the electricity price. Especially when electricity prices are low in times of high wind and solar PV production, they often become an important part of the deployment decision.

- For so-called controllable consumption devices, i.e. electric vehicles and heat pumps, at the low-voltage level, under Section 14a of the Energy Industry Act, grid operators are required to offer electricity customers time-variable grid fees as of 2025 in accordance with the corresponding Federal Network Agency rules (see also Box 17 in Chapter 3.4.2). For electricity customers connected at other voltage levels, grid fees have so far largely not provided any temporal or geographical signals that benefit the grid. They do not reflect local congestion situations or provide a time-differentiated indication of when additional local consumption can help to relieve the grid.[22]

- In principle, it is conceivable that grid fees will provide sufficient locational signals, both as incentives for regional behaviour that benefits the system and for regionally differentiated investment incentives.

- This would incentivise investment and dispatch and is used in the UK and Sweden, for example.

- It should be noted, however, that grid fees in Germany have so far only been charged on the feed-in and not the feed-out side, i.e. they only affect consumers on a regular basis and not producers.[23]

- Furthermore, new storage facilities and electrolysers are currently exempt from grid fees for a certain period of time (20 years). A regional differentiation of grid fees in the case of these technologies or grid users would currently have no effects.

- A proposal put forward by Agora Energiewende (2023) is to translate the current regional grid situation into grid fees; this is known as the **temporally and regionally differentiated grid fees** instrument. This approach has already been presented in the PKNS. What it means is that grid fees are temporarily reduced in the surplus region during periods of renewable energy curtailment as a result of grid congestion (Figure 18). This leads to lower electricity procurement costs for the consumer in the respective region and incentivises a short-term local increase in electricity demand.

- To this end, surplus regions and/or periods are identified in which the grid fees are reduced. This is particularly useful for foreseeable periods of strong winds in regions with high installed wind power generation capacity, as a large part

22 Under the current grid fee system, the grid costs are borne by the consumers who are connected to the grid in the grid area in which the grid costs are incurred. In recent years, regional differences in distribution grid fees have increasingly been caused by regional differences in the expansion of electricity generation from renewable energy sources and the corresponding differences in the associated grid expansion costs for integrating these generation plants into the grid. The Federal Network Agency is currently conducting a determination procedure to provide a balance. Other aspects that can already lead to regional differences in distribution grid fees systematically are differences in population density and the age of the grids.

23 Feed-in tariffs to temporarily incentivise plant operators to reduce feed-in in the event of acute grid bottlenecks are theoretically conceivable. However, adverse effects, such as on competitiveness in European wholesale electricity trading, will have to be considered. It would also be conceivable to collect an entry fee for grid access or grid connection in order to influence decisions on the location of new plants in the event of structural grid bottlenecks.

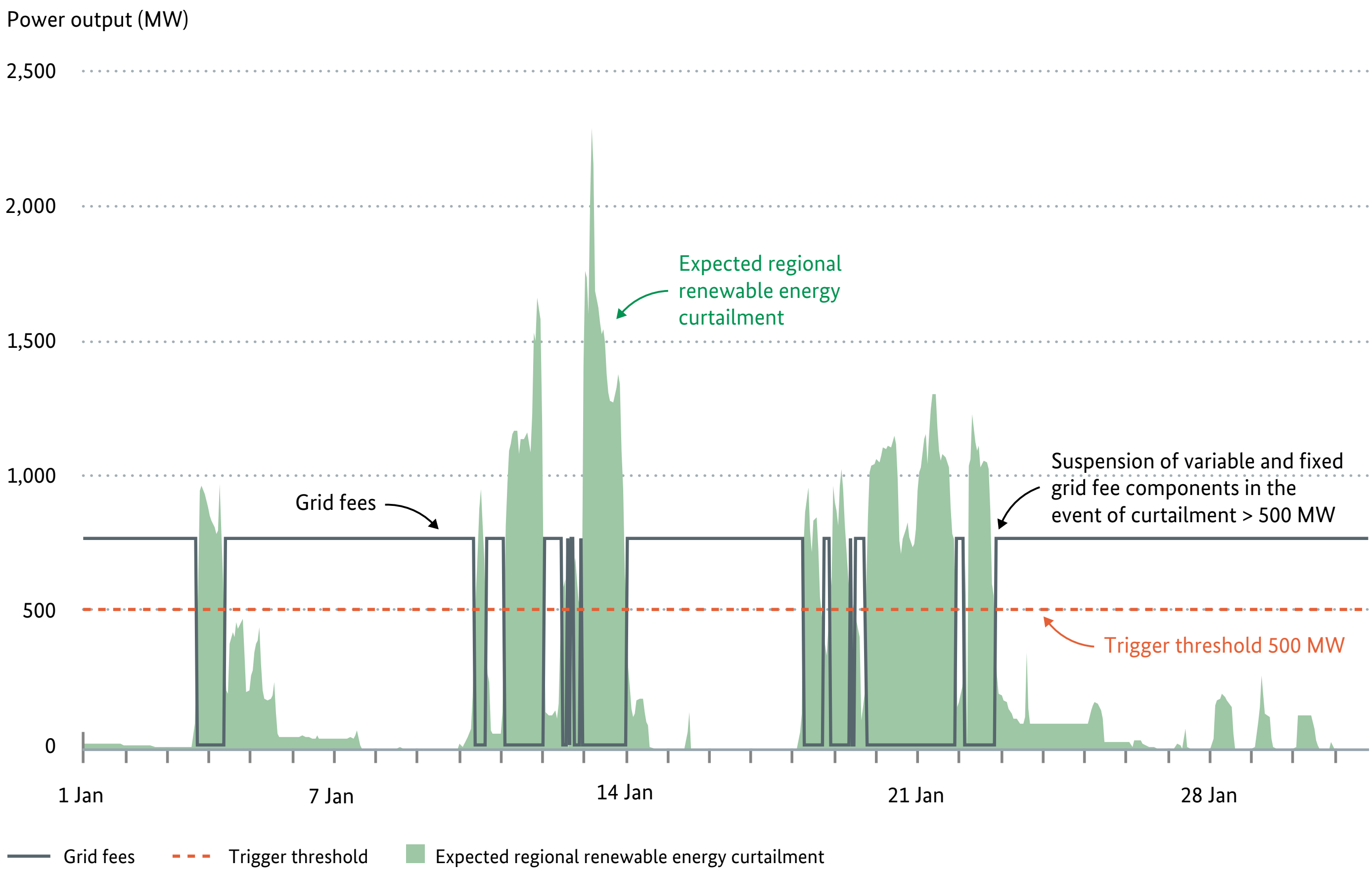
of the renewable energy curtailment affects wind power. However, the instrument is conceivable in principle in all regions with possibly only temporary or seasonal bottleneck situations. This will in future also include regions with high local solar PV generation, for example.

- The instrument works as follows: as soon as the expected curtailment volume exceeds a limit value, the grid fees are reduced for the period of the congestion situation. The grid operators announce these time windows with reduced grid fees at short notice, such as the day before a congestion situation is expected to occur, for example. Specifically, this could mean that in the hours in question, neither the energy price component of the grid fees is payable for the electricity consumption, nor is any peak load during this period included in the calculation of the power price components. In this context, it would also make sense to disregard the additional consumption in the approval of individual grid fees in accordance with Section 19 (2) (2) of the Electricity Network Charges Ordinance (Electricity Network Charges Ordinance.

- The prerequisite is quarter-hourly consumption metering and billing on the demand side.

- Maximum effectiveness of the instrument could be achieved by making it applicable to all relevant electricity consumers.

Figure 18: Suspension of grid fees in relation to the expected regional renewable energy curtailment (illustrative)



Source: Neon Neue Energieökonomik 2023

- The option makes it possible to provide flexibility to prevent transmission grid bottlenecks, for example, and to include more renewable energy generation in the system by incentivising loads that are already available locally, such as electric vehicles, heat pumps and industrial companies, and to consume more during times of congestion (dispatch incentive). In addition, the instrument can also incentivise investment for the local economy in regions with frequent curtailments, as the average expected electricity costs there are lower than in other regions (investment incentive). The latter is particularly effective if the instrument is credibly designed for the long term.

- The temporary reduction of grid fees in regions with a high level of curtailment will incentivize the local usage of green electricity instead of curtailing plants and could supplement the "Use instead of curtail" instrument that is already on its way.

- This also reduces grid congestion at transmission grid level, which means that grid operators have to carry out less redispatch. This supports secure operational management and also reduces redispatch costs.

- However, the grid operators' obligation to expand the electricity grids in line with demand must not be undermined by this under any circumstances.

The instrument leads, on the one hand, to lower income for the grid operators, while, on the other hand, it saves redispatch costs. The difference would have to be financed accordingly in order to avoid the DSOs being worse off financially as a result. According to Agora Energiewende (2023), a nationwide surcharge of the unpaid redispatch costs could be offered, as is already applied to the surcharge for individual grid fees in accordance with Section 19 (2) of the Electricity Grid Fee Ordinance. Alternatively, the lost grid fees from periods of grid congestion could be allocated to the regular grid fees payable in the region.

Responsibility for the introduction and design of such an instrument lies with the independent regulatory authority, the Federal Network Agency.

Opportunities:

- Overall, the measure can lead to more local use of surplus electricity (better renewable energy integration, thus also reducing CO_2 emissions), less curtailment and fewer grid bottlenecks (at least to the extent relevant bottleneck situations occur and have not already been reduced by grid expansion).

- The measure provides economic incentives for flexible loads to consume electricity in a way that benefits the grid both geographically and temporally. As a result, it also supports the flexibilisation of the demand side. In principle, all consumer groups (households, industry, business, etc.) with quarter-hourly billing can be addressed.

- The measure can incentivise new investments in flexible loads in regions with surplus electricity.

- If designed correctly, the instrument prevents disincentives for strategic behaviour/gaming on the electricity market[24], as all affected consumers benefit from the instrument, regardless of the originally planned consumption volume.

24 See Box 15 for an explanation of strategic behaviour on the electricity market in connection with congestion management

Challenges:

- The instrument sets locational signals for loads only, as producers in Germany currently pay no grid fees.

- The instrument requires consumption to be billed on a quarter-hourly basis, as it must be possible to determine what proportion of consumption takes place in time windows with reduced grid fees. This means that only consumption facilities with smart meters or a registered load profile metering (RLM) system could be addressed by the regulation.

- The instrument does not apply to loads that currently pay no grid fees (storage facilities, electrolysers). For large industrial consumers that benefit from reduced grid fees, the incentivising effect is only limited. As a result, the instrument would currently only address a small proportion of the loads, including important consumers such as large heat pumps, which have greater potential for shifting consumption to hours that benefit the grid. For a greater leverage effect, a combination with the existing grid fee exemptions would have to be considered.

- It should be discussed, for example, whether grid fees should only be suspended or reduced for loads at locations that benefit the system. This task is the responsibility of the independent Federal Network Agency.

- The instrument improves cost effectiveness in the electricity system by supporting behaviour that benefits the grid and thus reducing congestion and redispatch. However, the situational reduction in grid fees results in an overall reduction in income for the grid operators, which would have to be financed. Agora Energiewende (2023) proposes to solve this problem within the scope of the grid fee system by means of a nationwide roll-over.

- Various, even complex implementation issues would have to be clarified, including the choice of the implementation region, the level of the trigger threshold, the determination of the time of announcement and the interaction between distribution and transmission grid fees. It should be borne in mind that a short lead time is necessary in order to forecast congestion situations as accurately as possible and also that the corresponding competences and processes must therefore be established among all grid operators. On the other hand, from the perspective of plant operators and investors in particular, a longer lead time is important for planning reliability. To ensure that such an instrument can be implemented at the technical, organisational and economic level, it is crucial that its design is as simple as possible.

Option 2:
Regional signals in funding programmes

Explanation of the option for action:

- By **regional signals in funding programmes**, we refer to the possibility of setting direct regionally differentiated incentives or requirements within the scope of funding measures on the supply or demand-side. A regional component of this kind in funding programmes has the effect that more projects will be funded that are located at locations that benefit the grid or the system. This can be achieved by specifying funding conditions for siting of new loads and for new generation facilities, such as power plants.

- The aim is to use these instruments to control the siting of new generation facilities or additional loads, such as electrolysers in particular, in such a way that the challenges from a grid perspective are not increased, but at best even reduced.

- Such regional signals in funding programmes are planned as part of the Power Plant Security Act, but could also be implemented as part of the introduction of a capacity mechanism (see Chapter 3.2), for example, or as part of the funding of electrolysers.

- Regional signals in funding programmes are also possible when funding electricity generation (wind, solar and controllable capacities). Specific existing examples are the southern quota for biogas plants and, indirectly, the reference yield model of the Renewable Energy Sources Act. The latter will result in the funding amount for onshore wind power plants will be somewhat higher per kWh when generated at low-wind locations than for a comparable plant erected at a location with a higher wind yield. Even if the instrument as a result does not provide control that specifically benefits the grid, it will nevertheless lead to a more evenly distributed geographical expansion of wind power, which often tends to have grid-relieving effects. The southern quota for biomethane has been suspended with the solar package until the end of 2027. In the case of biogas, projects in the south are prioritised in the tenders, which has a positive effect on its benefit for the system.

- Possible forms of regional signals in tenders or other support measures would be as follows:
  - **Priority regions:** tenders for funding only for specific locations that benefit the grid. Expansion in other regions remains possible, but purely on a market basis without funding.
  - **Quota** for specific regions: as appropriate, a certain proportion of the tendered quantity is to be awarded in a defined region.
  - Differentiated funding amount: the funding amount would vary depending on the location (**bonus/penalty system**).

Opportunities:

- Regional signals in funding programmes would make it possible to design support measures that have already been planned in a way that benefits the system and are overall more effective. This would then make it possible to avoid or at least reduce additional system costs, such as increased redispatch requirements and higher grid expansion requirements in particular, which would arise if the siting of new generation facilities or loads did not benefit the system.

- Regional signals in funding programmes can provide targeted incentives for new investments in generation in regions with a high demand for electricity that benefit the system and for investments in additional loads in regions that generate large amounts of renewable electricity.

- Depending on the funding measure, regional signals in funding programmes would make technology-specific control possible. This would enable different regional effects of different technologies to be addressed. In the case of technologies for which a location that benefits the system is of great importance, such as electrolysers, for example, stronger control could be exercised than for technologies for which the question of a location that benefits the system is less important.

- Regional signals in funding can also partially address technologies that are not considered in other instrument options. For example, grid fee incentives as those in Option 1 are ineffective for consumers who pay no grid fees and for generation facilities, because no grid fees are charged on the feed-in side in Germany.

Challenges:

- Regional signals via funding measures addresses the siting decision only and not the deployment decision.

- Funding measures typically have to be approved as State aid by the European Commission. Regional components in support measures can make notification more difficult. Although the guidelines for State aid in recital 96 (e) and (f) explicitly make regional signals possible for systemic reasons (see European Union (2022)), the European Commission sets high requirements for evidence and prefers working towards local price signals for regional signals.

- Regional signals in funding measures can be at the expense of funding efficiency. The reason for this is that the lowest bidder in the tendering process is not automatically awarded the contract. Depending on how it is designed, this can also result in less competition for tenders and, in extreme cases, even favour market power.

- Tendering procedures will become more bureaucratic and complicated, since the funding design will have to be supplemented by regional parameters such as quotas or bonuses/penalties and the preferred regional locations will have to be determined centrally.

- The regional signals approaches differ in terms of how accurately they can influence the investment decision. Bonus/penalty regulations, for example, are difficult to parameterise to ensure that the desired control of the funded projects can be reliably achieved.

Option 3:
Demand response in congestion management

Loads cannot currently be used for redispatch. It is difficult at the moment in Germany to integrate loads into congestion management (redispatch). With an increasing volume of demand response in the electricity system, a large potential, therefore, remains unused. This raises the question of how this potential can be leveraged for redispatch. This is relevant not only with regard to the transmission grid, but also in particular for renewable energy-related bottlenecks in distribution grids, where demand response can also represent an important potential beyond the existing regulations in accordance with Section 14a of the Energy Industry Act.

Congestion management in Germany is organised as *regulatory redispatch*. As a result, grid operators are entitled to adjust the output of generation and storage facilities (ramping up and down) in the event that the grid status requires this to be done. The operators of the facilities are compensated financially as if the adjustment had not taken place by being reimbursed for fuel costs, etc. (see Box 13). Regulatory redispatch is therefore cost neutral for facility operators. At the same time, no player develops a commercial interest in the continued existence of a bottleneck. Regulatory redispatch in Germany to date has only covered generators and storage facilities, but not the loads on the consumption side.

Systematic problem: objective cost estimate for loads in redispatch hardly possible. It is difficult to include loads in regulatory redispatch. While it is possible to objectively estimate the revenues from electricity sales and fuel costs for generators, no objectively measurable costs are incurred when loads are curtailed. In fact, electricity consumers forego utility or production revenues they would have generated with the purchase of electricity. This lost utility is more difficult to quantify and can differ considerably between companies, individuals and over time. The curtailment of a charging electric car may have no costs whatsoever (if it can repeat the charging process at a later time) or very high subjective costs (if a holiday trip had actually been planned). For this reason, an objective determination of these costs and any subsequent compensation by the grid operator is difficult to accomplish.

Box 15

Strategic behaviour ("gaming", "increase-decrease") in redispatch markets

Redispatch markets are downstream of the spot market/wholesale market. Market players will therefore anticipate their revenue opportunities on the redispatch market when bidding on the wholesale electricity market and include their bids strategically in their bidding behaviour on the spot market.

Producer side: producers in regions behind the bottleneck, where there is little redispatch potential available, anticipate the bottleneck (wind front) and, by marketing their generation on the redispatch market, they can generate (higher) profits than on the electricity market. For this reason, they prefer to bid on the electricity market at much higher prices. In this way, they price themselves out of the electricity market in order to be available for the downstream redispatch market. The problem with this is that the bottlenecks get worse, as facilities that would have operated on the electricity market without the redispatch market and would have relieved grid congestion now no longer operate on the electricity market. Conversely, producers in regions with a large amount of electricity production ("surplus regions", for example, in northern Germany) anticipate profits by regulating downwards on the redispatch market. To make this possible, they must first be securely funded on the electricity market. They submit strategically low bids below their marginal costs on the electricity market. The spot market is where the market-clearing price is established, which is higher than the bids of the strategically low bidding producers, because other, more expensive units determine the price (merit order principle). On the redispatch market, which takes place later, the strategically active producers can then bid in such a way that the TSOs will instruct them to curtail and will subsequently be compensated for doing so. This allows them to effectively buy back the electricity they have not produced at a lower price.

Consumers: the same incentives shown in the example above for producers exist for consumers, albeit mirrored, but with the same congestion-increasing effect. Consumers in regions behind the grid bottleneck buy cheaply on the electricity market and sell on the redispatch market. Consumers in surplus regions withdraw from the electricity market to then buy cheaply on the redispatch market.

Redispatch markets are being discussed, but they raise new problems. In a redispatch market, the grid operators procure upward or downward redispatch to eliminate a grid bottleneck via a market. The provision of the respective redispatch service is voluntary. The most favourable offers for ramping up or ramping down are selected by tender and remunerated accordingly.

However, such redispatch markets are problematic, as they generally lead to strategic bidding by the market players (producers and consumers), which makes congestion worse.[25] Such strategic behaviour has been demonstrably observed in existing redispatch markets, such as in the UK.[26]

In Germany, bottlenecks are relatively easy to predict, so the strategic behaviour described above is very likely and plausible. Even if this is rational on an individual basis, it has significant consequences for the system. This strategic behaviour of market participants on both sides of the congestion leads to a worsening of the congestion and thus to increased redispatch volumes and costs. It also

25 Neon Neue Energieökonomik and Consentec (2019)

26 Perekhodtsev, D. and Cervigni, G. (2010)

carries risks for grid operation, as the TSOs base their grid planning on the schedules registered by the market players, although the information they contain is systematically distorted by strategic gaming (e.g. by registering too little generation). From an economic perspective, players can generate windfall profits, which results in incentives for business models and investments being created that are based solely on congestion.

Meaningful solutions for integrating loads into redispatch are important, but not easy. For these reasons, redispatch markets are problematic when bottlenecks are foreseeable. For the generation side, it makes thus sense to stick to the current principle of regulatory redispatch. As the integration of loads into regulatory redispatch does not appear to be possible, the question arises as to how loads can be integrated into redispatch without the problems described above. Ultimately, it comes down to the fact that there is an urgent need to incorporate the increasing potential of demand response into congestion management in a meaningful way.

One such option for including loads to resolve local bottlenecks was introduced with the "Use instead of curtail" regulation (Section 13k of the Energy Industry Act). This was discussed in the PKNS and implemented by the legislator in autumn 2022 with the aim of starting the trial of the instrument in October 2024. In situations with what would otherwise be high levels of renewable electricity curtailment, switchable loads are to be used to reduce the curtailment of renewable energy sources by means of additional consumption. The decisive factor here is that the electricity consumption is *in fact additional*, since this is the only way to achieve a bottleneck-relieving effect. The TSOs allocate discounted electricity to authorised participants. Participants must be located in regions in which they actually contribute to relieving congestion. The electricity is auctioned the day before by tender.

Systematically examine the integration of loads–Flexibility Agenda outlook. Further options for integrating loads into redispatch should be examined. In addition to other topics, this will be part of the coordinated Flexibility Agenda that is planned and which the BMWK will develop and discuss with the energy industry, stakeholders and experts (for details, see Chapter 3.4.2, field of action 3).

At the same time, however, the technical requirements must also be in place to integrate the loads into congestion management. Decentralised and small-scale loads, such as electric vehicles or electrolysers are connected to the distribution grids. To be able to leverage this potential effectively, the measurement, control, communication, in addition to forecasting capabilities, in particular, plus grid status monitoring of the distribution grid operators (DSOs), will have to be available on a large scale. Even if some DSOs are making progress in this area, the prerequisites in many cases are not likely to be available on a large scale until the end of the 2020s.

Summary of the locational signals field of action

- With a rising share of renewable energy sources and an increasing number of flexible electricity consumers, it is becoming increasingly important when and where we generate and consume electricity and how this is intelligently coordinated with the grid. Grid expansion and redispatch alone are not enough and it is also not effective to expand the grid down to the "last kW".
- Locational signals support a triad: significant acceleration of grid expansion, an efficient and secure redispatch at least as a short-term and transitional measure, in addition to locational signals.
- Appropriate locational signals ensure, on the one hand, that siting decisions of new capacities are made in a way that, as far as possible, benefits the system geographically. On the other hand, they incentivise producers and flexible consumers, to take local conditions and the situation in the electricity grids into account in making their operating/consumption decisions.
- Locational signals are not to be understood exclusively as price signals. In the BMWK's view, there are in principle a number of options to establish locational signals in the electricity market that can also be combined with each other: temporally/regionally differentiated grid fees, regional signals in funding programmes and the integration of loads in redispatch.
- The BMWK will continue to make progress on these issues within the scope of its responsibilities[27] and, for example, deal with them in depth in the planned Flexibility Agenda.
- The Federal Government's Initiative for Growth has also decided to introduce time-variable regional grid fees for using the grid in a way that benefits the system and ensuring that electricity storage systems are optimally used for the electricity market and the grid.

Key questions for the consultation:

Beyond the grid fee issues, the introduction and organisation of which fall within the responsibility of the independent regulatory authority:

1. What role do you see for locational signals in the future?
2. What are the benefits and drawbacks of the options presented for locational signals?
3. What approaches do you see for establishing locational signals in the electricity market in order to incentivise efficient use/consumption and investments that benefit the system geographically?
4. What risks do you see if it is not possible to establish suitable locational signals in the electricity market?
5. How can local price signals be structured as simply as possible so as to reduce new complexity and any implementation difficulties?

27 It should be noted that the independent regulatory authority, the Federal Network Agency, is responsible for the introduction and structuring of grid fees.

Excursus: Bidding zone

The BMWK is committed to maintaining the single German-Luxembourg bidding zone. However, an objective discussion on the subject of the electricity market of the future and locational signals will also have to address the topic of a potential reconfiguration of the bidding zone. For this reason, the subject was also discussed intensively in the PKNS.

Splitting the bidding zone would lead to different prices between the bidding zones whenever the transmission capacity of the electricity grid is limited. This would give market participants a signal as to the grid situation and allow them to optimise their behaviour accordingly.

The following arguments are presented as potential benefits of a bidding zone reconfiguration:

- Holistic approach to local price signals for all market participants, both in terms of investment incentives for new market players and with regard to dispatch incentives for flexible consumers;
- Dynamic mapping of the current system situation every quarter of an hour for all market players;
- Lower redispatch requirements and grid stability with a high share of renewables;
- Congestion income (from the management of domestic interconnection points)[28] which can be reinvested in grid expansion;
- Easing of the European debate, which, in view of loop flows (flows from northern to southern Germany through other EU MS) is pressing for a bidding zone reconfiguration in Germany.

There are serious challenges to overcome, however:

- Liquidity of the respective electricity market in each bidding zone would decrease; precisely on the competitive futures market, liquidity is an important prerequisite for long-term hedging against electricity price fluctuations, which in turn benefits the electricity customers through lower prices;
- In smaller bidding zones, electricity procurement costs can rise, as there are fewer – and therefore less favourable – options available in the individual zones;
- the market values of renewables in zones with a high share of renewables would fall, which increases the funding requirements under the Renewable Energy Sources Act. Inversely, market values in zones with a lower share of renewables would increase. The economic viability of previously subsidy-free, purely market-based renewable energy projects would also change significantly;
- High complexity and distribution effects;
- stability of the split in the middle of the system reorganisation unclear; ongoing reconfigurations would have a considerable impact on investment security;
- effects on grid expansion unclear: on the one hand, incentive increases (for southern consumers); on the other hand, there would be economic winners and losers in the grid expansion and thus possibly new resistance.

Due in particular to the high level of complexity in the midst of system restructuring and the distribution effects, and in view of the competitiveness of the industrial centres, reconfiguration is not currently considered as an option.

28 The TSOs are already auctioning transmission rights at the borders. In 2022, the German TSOs received a total of 1.82 billion euros from this (Federal Network Agency (2023 b)). The TSOs are required to fully invest the income generated from this (so-called congestion pension) in the grid in order to reduce congestion, in particular by expanding the grid. This can then be used to reduce grid costs for the benefit of electricity customers.

3.4 Leveraging demand-side flexibility potential

3.4.1 Role of flexibility in the decarbonised electricity system

Flexibility paradigm shift

Flexibility is becoming the key feature for competitive electricity prices and an efficient, climate-neutral electricity system. Historically, there has been no need for flexible demand on the electricity market in Germany. Stable, continuous demand was ideal for the operation of power plants at the time and also for the electricity grids. This has changed fundamentally because wind and solar PV power are now the volume generators in the new electricity system and in many hours produce very cheap electricity.

Consumers now have the opportunity to benefit from these very low electricity prices through flexible load shifting by charging their electric cars or loading the storage system at midday, for example. Business and industry can optimise their processes; the ramp-up of storage technology makes additional options available. As a result, flexibility is now the third, key pillar for competitive electricity prices besides the renewable energy ramp-up and grid expansion, and thus for the future viability of Germany as a business location. However, those consumers who are not flexible will also benefit indirectly as average electricity prices and system costs will fall when demand drops during expensive electricity hours and is made up for during more favourable hours.

Flexibilisation is therefore a paradigm shift for the question of how and when we consume electricity in Germany.

Flexibility helps to reduce overall system costs. This is because flexibility smooths price curves, reduces hours with negative or very low prices, thereby increasing the market value of renewables and reducing the costs of funding renewables (Chapter 3.1). Flexibility also reduces the costs of a capacity mechanism (Chapter 3.2). Without appropriate flexibilisation, a capacity mechanism ultimately becomes more inefficient and more expensive, as hedging the last kWh with power plants alone becomes too costly.

In addition, the grid operators can also use demand response to support the grid using appropriate price signals for the provision of ancillary services, for example, or to relieve congestion (Chapter 3.3).

Demand-side flexibility therefore has multiple benefits:

- Everyone can benefit from affordable electricity prices and competitiveness is strengthened,
- the integration of renewables is optimised and their support costs reduced, and
- security of supply is increased and costs of a capacity mechanism are reduced.

A broad mix of technologies is available for flexibility – in Germany itself and in the European internal market. Many different technologies can be considered as flexibility options: flexible power plants, flexible demand, storage facilities and efficient electricity grids – in Germany itself and in the European internal market. Consumers can either make their electricity consumption more flexible themselves or, if this is not possible or opportune, they can make use of the flexibility in the system. An efficient electricity grid can act as a large storage facility. It connects Germany with other windy and sunny regions and thus extends the time in which households and companies can benefit from cheap renewable electricity. It connects us with the large storage facilities in the Alps and Scandinavia.

As a result of sector coupling, new flexible applications, such as electric vehicles, heat pumps, storage systems and electrolysers are arriving on the scene. These players are able to adapt their electricity consumption to hours of wind and sunshine. However, industrial consumers that electrify processes as part of decarbonisation– depending on their production methods – can make their electricity consumption more flexible and become new flexible consumers.

By 2030, electric cars, home storage systems and heat pumps will have twice as much installed capacity as large-scale flexibility options such as electrolysers, large heat pumps and electric boilers. In an optimistic scenarios, if using these flexibility options, households can shift up to 100 TWh of electricity demand to other times.[29]

The price signal is pacemaker in this dynamic scenario. High prices create an incentive to reduce consumption and make up for it later when prices are lower. When prices are low, the mechanism is precisely the opposite. The price is therefore the key signal for the situation on the electricity market and indicates that a shift in electricity consumption will relieve the situation and contribute to security of supply. The prerequisite for this to happen is that demand can respond flexibly to lower prices.

For the optimum use of demand-side flexibility options, however, numerous obstacles are still present. The electricity price signal from the electricity exchange is often unable to develop its full effect. The obstacles can be broken down into three categories:

1) technical, 2) regulatory and 3) economic obstacles. These prevent existing flexibility potential from being used and investments in flexibility options from being made. The removal of these

Box 16

Technical basis: digitisation of the energy transition

The communication infrastructure in the electricity system was originally designed for a limited number of larger, mostly generation-side flexibility options, such as data exchange with large power plants. Existing processes and systems today are therefore suitable for integrating decentralised consumers into the electricity system to a limited degree only. The accelerated roll-out of the smart meter infrastructure based on the Act to Relaunch the Digitisation of the Energy Transition digitally connects household-related flexibility options, while guaranteeing data protection and cyber security. BSI TR-03109-5 (“communication adapter”), which came into force on 1 January 2024, provides the required technical standard for controlling and switching generation systems and controllable consumers (e-cars, heat pumps, storage systems). The legislator relies on digitisation to make a flexible and decentralised electricity system more resilient. In implementing this mandate, the BMWK presented a comprehensive digitisation report as at the reporting date of 30 June 2024. This sets out the regulatory scope for action to strengthen system benefits and resilience through digitisation.

In addition, the digital infrastructure must also be capable of coordinating the large number of new players and systems. Without digitisation of the electricity system, the use of decentralised flexibility cannot succeed: It creates transparency on the current state of the electricity system and enables end consumers to participate in the energy transition project for society as a whole.

29 Agora Energiewende and Research Centre for Energy Economics e.V. (2023)

obstacles is fundamental to a climate-neutral electricity system; regulatory and economic obstacles must therefore also be addressed in the discussion about the future electricity market design. The purpose of removing obstacles is to allow market players to decide for themselves what kind of flexibility they would like to have. This freedom of choice must be guaranteed, however.

An urgent need for action to increase the potential for flexibility was recognised both nationally and throughout Europe. In the PKNS, flexibility was named as an urgent issue, the need for action was identified and solutions were outlined. With the electricity market reform, Europe is also placing a new focus on flexibility potential. The Member States must set themselves a flexibility target and, in a roadmap analyse identify existing obstacles and find solutions.

3.4.2 Areas for action to reduce obstacles to flexibility

In addition to accelerated digitisation, from an electricity market perspective, three areas for action are key to removing obstacles to demand-side flexibility potential. These are: (1) paving the way for dynamic and innovative tariff models, (2) further development of the grid fee structure, for example, in the direction of time-variable grid fees, and (3) enabling flexibility even in the case of discounts (while maintaining the competitiveness of industrial consumers).

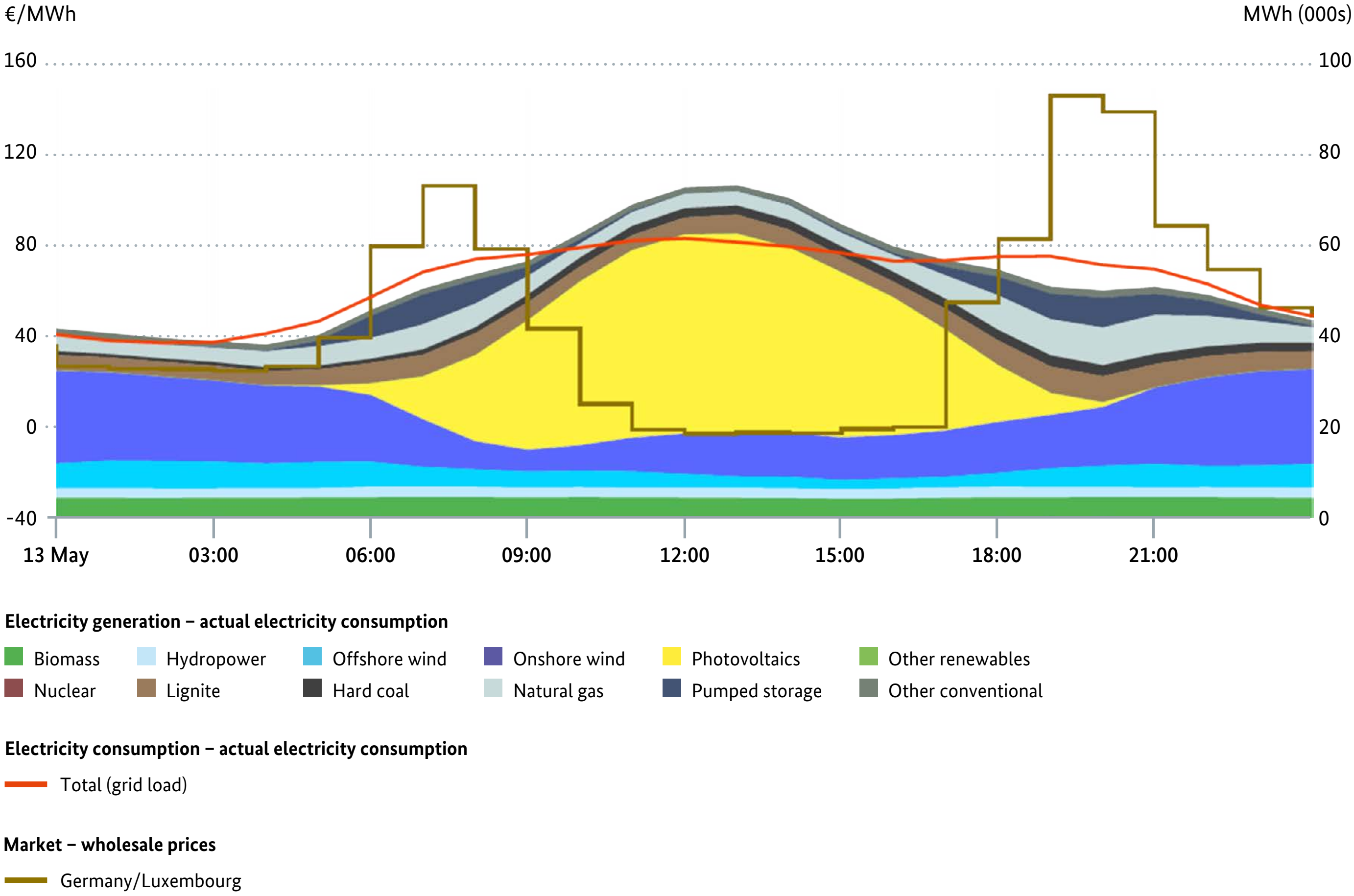
The areas for action complement each other and do not represent mutually exclusive approaches.

Area for action 1:
Enable price response – paving the way for dynamic and innovative tariff models

Dynamic and innovative tariff models have significant potential to lower electricity prices. While industrial consumers generally use dynamic tariffs today, this is not yet the norm for households. Dynamic tariffs are characterised by dynamic price components in the procurement share, which reflect the spot market price. Contracts with fixed electricity tariffs are the standard today in the household customer segment. This means that customers with fixed-price tariffs are not yet able to take advantage of electricity prices on the electricity exchange that even now are frequently low. As a result, households with corresponding consumption systems have no financial incentive to make use of their flexibility (e.g. electric car or heat pump) to benefit the electricity system.

The Act to Relaunch the Digitisation of the Energy Transition requires all suppliers to offer an electricity contract with dynamic tariffs as of 1 January 2025. By having readings for customers with smart metering systems transmitted at quarter-hourly intervals nationwide in accordance with stricter data protection requirements, flexible customers in future will no longer be identified by means of the standard load profile. This means that these customers will be recognised on the basis of their individual consumption profile and in this way their response to electricity price signals will also be taken into account in the suppliers' procurement strategy and thus on the electricity market.

Figure 19: Generation, consumption and day-ahead electricity price in Germany on 13 May 2024



Source: Federal Network Agency on the basis of SMARD (2024 b)

Figure 19 takes the example of 13 May 2024 to show what the electricity feed-in profile of the future could look like: with high wind and solar PV generation. However, it also shows that, on the whole, demand continues to remains stable today. Although the electricity price on the electricity exchange fell continuously from 9 a.m. until it reached almost zero euros/kWh between 11 a.m. and 5 p.m., demand hardly responded at all. The figure also shows what savings would be possible for flexible customers at these times.

Wide variety of dynamic and innovative tariff models with risk grading. The conclusion of electricity contracts with dynamic tariffs is voluntary for customers.

To identify the customers' preferences, the variety and attractiveness of the tariffs offered are therefore a key factor. Flexibility from heat pumps or electric vehicles can be increased significantly, particularly in the event that the tariffs offered reflect the varied preferences of the customers. Of particular relevance is the attitude the customers have towards fluctuating prices and their need for ease and convenience when controlling flexible systems. The reason for this is that, in the case dynamic tariffs, there is always the challenge of being faced with temporarily high or persistently high market prices, which will then have a direct effect on end customers' prices.

For this reason, the possible solution space not only includes the dynamic tariffs specified in the Energy Industry Act, but also time-variable tariffs with fixed price levels (time-of-use tariff), for example, or dynamic tariffs with a price hedging component. Fixed-price tariffs are also conceivable in which service providers (so-called aggregators) take control of the flexibility options and pass on some of the resulting financial added value to the households. With a wide range of tariffs available, the varying willingness of end customers to take risks can be reflected in the prices of the tariffs. Whatever the case, it is important to create transparency for customers, e.g. by creating opportunities for comparison and communicating risks and opportunities in an understandable way.

Developing and providing such offers is the task of an end customer market that operates on a competitive basis. The task of the state is to create the necessary framework conditions.

Smart meter rollout and digitisation as important factors. The rollout of smart meters is an essential prerequisite for the ramp-up of dynamic tariffs. To accelerate this process and eliminate the red tape, the Act to Relaunch the Digitisation of the Energy Transition was introduced. Now that the rollout has restarted, it is important to make the positive development permanent. The immediate task is to fully leverage the significant benefits of digitisation for system stability and the national economy. With the digitisation report in accordance with Section 48 of the Metering Point Operation Act, a separate process, in which proposals are submitted for the further development of the legal framework, is in place to do this.

Digitisation offers enormous potential for making consumption optimisation attractive, but also for linking it to the requirements of reliable grid operation and controlling it intelligently.

The ramp-up of dynamic tariffs and other models that enable price responses needs to be monitored. At present, there is still reluctance to introduce dynamic tariffs, in particular because the technical requirements are lacking, but also because there is generally little practical experience available. One reason for this reluctance on the grid operator side is the fear that, with the ramp-up of dynamic tariffs, responses to price signals that are "too" strong and simultaneous will occur in the medium term. The flexible demand for electricity would then concentrate solely on the hours with the most favourable prices, which in turn would lead to challenges in terms of the system operation.

As a result of similar daily routines in the household sector, there is already, i.e. without external price or control signals, a high concentration of consumption today. Even with no price signal, this challenge may arise with the increasing number of electric cars and heat pumps. Whether, as a result of introducing dynamic tariffs, a mitigating effect will actually occur, because today's load peaks will be reduced by load shifting, and at what point, due to a very high degree of automation in the charging processes of electric vehicles, for example, new concentration peaks will occur, is not possible to foresee at the moment. This makes it all the more important to have monitoring and control options on the grid side, such as those available to grid operators via the measures specified in Section 14a of the Energy Industry Act. Whether this happens or not, acquiring experience must begin today. To this end, the Federal Network Agency should closely monitor and evaluate the ramp-up of dynamic tariffs and their effects on the grid and the market (e.g. via a corresponding explicit regulation in Section 35 f the Energy Industry Act) and, if necessary, draw attention to the need for adjustments at an early stage.

Area for action 2:
Opportunities of a new grid fee structure for using the electricity market and energy transition

Grid fees stand in the way of a flexible response to electricity market demand. End consumers pay grid fees for the provision and use of the grid infrastructure. Grid fees are the second-largest component of the end customer price, while procurement costs on the wholesale market are still the major component.[30] This means that grid fees are of considerable importance as a price component that controls behaviour. Like all other taxes, duties and surcharges, grid fees can reduce the incentive for consumers to respond to price signals from the market by the simple fact that they are added to the electricity exchange price.

The discussions in the PKNS have shown that in Germany the grid fee system itself, i.e. the way in which the level and distribution of fees is determined, can also represent an obstacle to flexibility. With regard to the electricity market design of the future and the question as to how supply and demand will be brought together, grid fee issues therefore must always be addressed.

In Germany, the Federal Network Agency is responsible for any adjustments to the grid fee system, taking into account the requirements of European law.

Box 17

Grid fees in the electricity system

Grid fees account for a significant proportion of electricity costs for most consumers. Industrial consumers paid an average of €33/MWh (excluding concessions), while the figure for companies was no less than €74/MWh (Federal Network Agency 2023 e). This was equivalent to around one third or almost three quarters of the average wholesale electricity price (€90/MWh). The grid fee system differs fundamentally between small and large consumers.

In Germany, the grid fee for households and small companies generally is made up of a base charge (euros per month) and a work charge component (ct/kWh). In the tariff area, the so-called time-variable HT/LT (high tariff/low tariff) tariff levels for end customers with night storage heaters has been in place for a long time. An extension of this tariff model that includes time-based grid fees (time-variable grid fees), in addition to several time windows and different user groups, is not yet widespread in Germany. If adequately structured, this would better reflect the time-of-day-based grid use and thus provide a better incentive for behaviour that benefits the grid. As of 2025, grid operators will be required to offer such a fee for specific flexible consumers, such as heat pumps and electromobility in the low-voltage grid (specified by the Federal Network Agency in accordance with Section 14a of the Energy Industry Act).

Another form would be a differentiated grid fee that is adapted to the respective grid situation and could therefore influence grid usage behaviour in the very short term by means of a price signal. Implementing this in practice would present many additional challenges for the energy industry; it is all the more important in this case, therefore, to have practical research and testing opportunities for innovative players.

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For industrial and commercial consumers with registered load profile metering systems (RLM customers), the grid fee is made up of a consumption charge and a work charge component. The consumption charge is usually based on the highest quarter-hourly consumption of each customer per year (euro/(kW*a)) (individual annual peak consumption) and the so-called hours of use (ratio of annual work to annual peak consumption; greater or less than 2,500 hours). The work charge is levied for the amount of energy consumed (ct/kWh).

In accordance with Section 19 (2) of the Electricity Grid Fee Ordinance, RLM customers receive individually lower grid fees if their peak load contribution deviates from the simultaneous annual peak load in the grid area (atypical grid use) or if the electricity consumption from the grid exceeds the hours of use limit of at least 7,000 hours per year and electricity consumption is greater than 10 GWh per year (continuous electricity consumption).

These principles of the grid fee system were laid down in the Electricity Grid Fee Ordinance in 2005, almost 20 years ago.

With the entry into force of the last amendment to the Energy Industry Act in January 2024, the independent Federal Network Agency has been given sole responsibility under European law for the design of the grid fee system. It must now revise the existing regulations by 2028 and therefore has the opportunity to adapt the grid fee regulations to the conditions of the climate-neutral electricity system.

The flexibility incentive has not yet been implemented in the grid fees for small consumers. As the work charge is usually constant throughout the year, small consumers have no grid-based incentive to shift their electricity consumption to other times. In addition, a high grid fee compared with the exchange electricity price can also reduce the incentive for small consumers to choose a dynamic tariff and adapt their consumption behaviour to the supply from renewables.

The Federal Network Agency's determination under Section 14a of the Energy Industry Act, which states that grid operators must also offer a time-variable grid fee for end customers with controllable consumption devices, such as heat pumps or electric vehicles as of 2025, is intended to remedy this situation. This gradual introduction of time-variable grid fees will be evaluated by the Federal Network Agency and its impact assessed. It is also important to work out in this context how two price signals, i.e. the exchange electricity price signal passed on via dynamic tariffs and the grid signal via the time-variable grid fee, can stimulate the behaviour of the demand side as a joint and possibly at times opposing signal. The interaction should be tested promptly in practice in pilot projects involving grid operators, suppliers, aggregators, the regulatory authority and research.

Grid fees for large consumers inhibit flexibility on the electricity market. The grid fee structure for large consumers currently favours the **uniform consumption** of electricity. It can therefore counteract flexible behaviour and the creation of opportunities for low electricity prices. The consumption charge for industrial and commercial consumers means that an increase in the annual peak load due to increased power consumption during strong winds, for example, will result in high additional costs.

Increasing the use of wind and solar power is therefore often financially unattractive for these consumers, even when exchange prices are quite negative. However, the energy transition makes flexible consumption of electricity essential. This includes both ramping up when prices are low and reducing the load when prices are high. It is therefore necessary to find solutions for grid connection and grid fee models that will enable this flexibility on both sides and at the same time refinance the grid costs.

It is not individual load peaks, but a high simultaneous load in the grid area that pushes the electricity grid to its limits. In view of this situation, the question arises as to whether the individual load peak, detached from the situational grid status in the grid area, should still be a deciding factor for the level of grid fees in future. An examination can be made to determine, for example, whether the individual consumption charge can be replaced by an instrument that also takes the grid load into account. Here again, time-variable work charges for grid fees would appear appropriate as a first step. This would make shifting load from hours with high grid load to hours with low grid load financially attractive. The PKNS also discussed variants of a capacity price that could contribute to refinancing the high fixed grid costs.

Reform the EU framework for grid fees and make it fit for the requirements of the future electricity system. The framework regulations for the structure of grid fees in Europe are defined. Although they offer the Member States a lot of room for manoeuvre, they nevertheless lay down the guidelines for national regulations in Europe. These include, for example, the fact that grid fees must be cost-based and non-discriminatory. Tariffs must also be transparent and create incentives for efficient grid use. With regard to the climate-neutral electricity system, the aim in Europe will be to specify these principles and, if necessary, to convert the framework to flexibility-promoting regulations that will also allow the grid infrastructure to be refinanced.

A flexibility-enabling grid fee structure is important for the success of the energy transition. A suitable grid fee structure can leverage flexibility potential for the electricity market and also reduce the grid load of new consumers. At European and national level, the future grid fee system should be aligned with the requirements of a climate-neutral electricity system. The focus should be on optimising the overall system (including the most efficient and reliable grid operation possible), regulatory complexity should be reduced and few exemptions needed.

Area for action 3:
Enable industrial flexibility, develop individual grid fees further – maintain industrial competitiveness

On 24 July 2024, the Federal Network Agency launched a procedure for a determination that deviates from Section 19 (2) of the Electricity Grid Fee Ordinance to set incentives that benefit the system by means of a special grid fee for industrial customers, and also published a key issues paper relating to it. With regard to the electricity market of the future, this is a key step towards enabling flexible electricity demand from industry.

Individual grid fees reward "constant electricity consumption" – flexibility is inhibited. Large consumers can receive a reduction in grid fees in the form of *individual grid fees* under the provisions of Section 19 (2) of the Electricity Grid Fee Ordinance.

The reduction is linked to one of two conditions: either "uniform grid use" or "atypical grid use". Many large industrial consumers would receive a discount of up to 90 per cent on their grid fees as a result of this regulation.

"Atypical grid use" occurs when the maximum electricity consumption can be predicted outside defined maximum load time windows. This regulation on average affects significantly smaller consumers. Behaviour that benefits the grid for the purpose of avoiding or delaying grid expansion by avoiding load peaks makes sense when properly calibrated. The current methodology and the rigidly specified time windows with a long lead time fundamentally contradict the need for short-term flexibility in consumption. In this respect, it should be discussed to what extent behaviour that benefits the grid by avoiding individual peak loads during times of highest grid loads will have to be fundamentally redefined. Regulating the corresponding discount on grid fees is the sole responsibility of the Federal Network Agency.

In the case of "uniform grid use", consumers must consume at least 10 GWh of electricity and achieve at least 7,000 hours of use (ratio of annual work to annual peak consumption) per year ("7,000-hour rule"), which is equivalent to almost constant electricity consumption. If a company increases its electricity consumption in the short term in order to benefit from cheap, green electricity during hours of sunshine or wind, this will lead to a reduction in the hours of use and will thus jeopardise the discount. The same applies in reverse if a company reduces consumption during price peaks. In this way, the discount counteracts a flexibilisation of demand.

Companies today use existing flexibility potential to optimise grid fees, not consumption. Existing electricity storage systems behind the meter, self-consumption systems and flexible consumption processes are frequently not used by the companies receiving a discount in order to benefit from fluctuations in the electricity price and the generation of renewable energy sources. Instead, the grid fees create false incentives to use flexibility in order to optimise the grid fees – instead of using flexibility in an optimum way, while keeping an eye on the requirements of the overall system. This makes the integration of renewable energy sources more difficult because the consumption of electricity is not the first choice when there is a lot of sunshine or wind available.

Need for adjustment is generally recognised. The need for action is generally recognised from an electricity market perspective and was highlighted in the PKNS as one of the main obstacles to making industrial consumption more flexible. The Federal Network Agency, as the responsible regulatory authority, has also recognised the problem.

It has therefore issued a regulation that will remain valid until 2025, in accordance with which consumption may be made more flexible without the discounts being dropped. This was updated again in June 2024 in order to remove obstacles to increasing the load.[31]

In future, "constant electricity consumption" should no longer be the trigger for exemption from grid fees. From a system perspective, the idea of atypical grid use in Section 19 (2) (1) of the Electricity Grid Fee Ordinance is a step in the right direction if calibrated appropriately, as consumers will be encouraged to increase their consumption outside the defined peak load time windows. However, the regulation should also be further developed and reviewed to determine, for example, whether it makes sense to define time windows differently and, if necessary, specify several time windows.

Any further development should keep a sense of proportion and be linked to transitional arrangements, while ensuring that those receiving a discount and the volume of the discounts remain as constant as possible, but should place the discount on a footing that is "compatible with flexibility", in order to enable electricity-intensive companies in the market to benefit from the opportunities offered by flexibility.

The Federal Government's Initiative for Growth has made a decision in this respect: *"Beyond this, it is important to create security for companies that benefit from the application of individual, reduced grid fees pursuant to section 19(2) sentences 1 and 2 Electricity Grid Fee Ordinance and to further develop these in a future-oriented manner. As a step to achieve this, obstacles to flexible electricity consumption are to be removed. Companies should be able to benefit from low electricity prices in times of an abundance of wind and sun. For those companies for which this is not possible, we will extend the existing rules in accordance with section 19(2) sentences 1 and 2 Electricity Grid Fee Ordinance in a manner that is compatible with state aid rules and take measures that prolong the corresponding impact of the relief measures (e.g. through financial assistance/exemption from grid fees for storage facilities).*

Many of the measures fall within the responsibility of the Bundesnetzagentur. The Federal Government therefore welcomes the Bundesnetzagentur's plan, as an independent regulatory authority, to further develop the current discounts and exemptions from grid feeds for industry, electrolysers and other new electricity consumers with the aim of enhancing the cost-efficiency of the electricity grid in a way that serves the overall system and the electricity market, and to create long-term planning security."

Choose a capacity market design that unlocks flexibility. In addition, it is imperative that a capacity market design is chosen that makes good use of flexibility. If flexibility has no effective access to the capacity mechanism, then the business case may even deteriorate as other controllable capacities will enter the market via the capacity mechanism.

A coordinated Flexibility Agenda

The BMWK will continue to build on the fields of action identified in the light of the consultation on this paper and draw up a coordinated Flexibility Agenda that will clearly identify goals, needs, potential and obstacles. On this basis, working closely with the responsible authorities, the energy industry, business, stakeholders and experts, solutions are to be developed and obstacles removed. The European requirements from the latest reform of the internal electricity market regulations provide the framework for this.

31 See Federal Network Agency (2024 c). For example, an increase in consumption in the six hours around the lowest wholesale price on the previous day is no longer included in the calculation of the 7,000 hours of use.

Summary of the flexibility field of action

- The flexibility of electricity producers and consumers is of paramount importance in a climate-neutral electricity system in order to balance out the variable electricity generation from wind and solar PV and to bring generation and supply together at all times.
- The extensive use of flexibility is still hindered today by technical, regulatory and economic obstacles in particular.
- The BMWK is therefore planning a coordinated Flexibility Agenda to tackle these obstacles in a systematic and structured manner.
- Furthermore, it is imperative that the capacity market design chosen makes good use of flexibility.
- The Federal Government's Initiative for Growth also aims to reduce the obstacles to flexibility caused by individual grid fees and to find solutions and planning security for all companies.

Key questions for the consultation:

1. Do you agree with the problem description and the key messages?
2. Is the list of areas for action complete and how do you assess the individual areas for action?

Beyond the grid fee issues, their introduction and structure that fall within the responsibility of the independent regulatory authority:

3. What specific obstacles to flexibility on the demand side do you see and what solutions do you recommend?
4. What specific options for action do you see?

4 Summary of the fields of action for a market design of the future

Options space for a secure, affordable and sustainable market design

The fields of action and options presented in this paper are building blocks for the architecture of the future electricity market design – there are alternative options within the fields of action, while other options complement each other (Figure 20). What they all have in common is that they fulfil the requirements for a secure, affordable and sustainable electricity market design of the future, as identified in Chapter 2. Some building blocks build on each other and can be combined well, while other building blocks are mutually exclusive alternatives. Each of the options within the fields of action for financing renewable energy sources and controllable capacities, for example, represents an alternative. In contrast, the areas for action in the flexibility field of action can be combined with each other, as can the options in the locational signals field of action.

Focus on the interrelationships between the fields of action

There are also interrelationships between the fields of action and the respective options. These represent, on the one hand, an opportunity if they reinforce each other – on the other hand, they can also become a challenge if instruments work against each other. Costly mistakes and challenges for a secure system must therefore be avoided wherever possible.

Flexibility is key to (1) the financing costs in the capacity mechanism and (2) the financing costs of renewables.

- If consumers have economic incentives for inflexible behaviour as a result of the grid fee structure (see Chapter 3.4), this would make the capacity mechanism more expensive overall because it would have to "override" another regulatory area or otherwise more expensive technologies would be considered in the capacity mechanism.

Figure 20: Overview of fields of action and options

Renewables	Sliding market premium with refinancing contribution	Production-based, two-way contract for difference (w/o market value corridor)	Non-production-based, two-way contract for difference	Capacity payment with non-production-based refinancing contribution
Controllable capacities	Capacity safeguarding mechanism through peak price hedging	Decentralised capacity market	Central capacity market	Combined capacity market
Locational signals	Temporally/regionally differentiated grid fees	Regional signals in funding programmes	Demand response in congestion management	
Flexibility	Enable price response – implement dynamic and innovative tariff models	Adapt grid fee system to promote flexibility	Enable industrial flexibility and reform individual grid fees	

- For the **financing of renewable energies**, it is important that the demand for electricity in particular can respond as flexibly as possible to wind and solar PV, so that the market values of renewable energies are stabilised, subsidy costs are reduced as a result and curtailments avoided.

The integration of locational signals into the investment framework for renewable energies and controllable capacities, in addition to unlocking flexibility – depending on the specific structure – can lead to excellent opportunities:

- The siting of new, **flexible consumers, such as electrolysers, in addition to new power plants and storage facilities** will take place where they at least do not make bottlenecks worse or may even relieve them by the provision of system services or congestion management.

- Locational signals are important to ensure that the various **flexibility options** in the electricity system are used to match the current grid situation. Flexibilities can therefore benefit the system significantly if they are accompanied by locational signals. For demand response in windswept regions, for example, stronger incentives would be provided to shift consumption to hours of windy weather if grid fees were lowered at corresponding times.

The options for safeguarding of renewable energies and controllable capacities have some parallels, but the objectives differ in many respects. In both fields of action, there tend to be similar challenges to safeguard the required investments, in addition to parallel requirements of the European legal framework.

- Overall, the discussions on the fields of action relating to financing renewable energies and controllable capacities indicate that a new, common philosophy for a market design will develop, the focus of which will be on cost-effective refinancing of fixed costs through appropriate safeguarding of investment risks.

- The fluctuating renewable energy sources wind and solar PV on the one hand and controllable capacities on the other have different objectives and functions in the electricity market (green electricity compared with resource adequacy). These different objectives and system functions of the technologies make it necessary for the future market design – as is already the case with today's market design – to recognise and allow for different products. For this reason, joint tenders for controllable and variable capacities do not appear to be constructive per se. What they do have in common, however, is that investors need a reliable long-term framework to hedge the risks of their investments.

- Moreover, as a result of the European requirements, a repayment mechanism is emerging as a fundamental market design feature – although the repayment mechanism is likely to be structured differently for the individual technologies due to their different functions and subsequently for the ways in which they will be used.

Consider interrelationships with other sectors and segments of the energy market

When designing the future electricity market, interrelationships with other segments of the energy market, such as ancillary services and heat generation, will also have to be taken into account.

- Controllable capacities in particular often provide additional services within the electricity system or beyond. Examples of this are the provision of system services required to stabilise the electricity grids, heat generation or ecosystem services (such as the handling of slurry). These services have a value of their own that goes beyond electricity generation and are therefore sometimes remunerated via special market segments, in some cases, however, also via funding mechanisms.

- There are close interrelationships with the electricity sector, particularly in the area of heat supply. This applies in particular to heat generation plants such as CHP plants, large heat pumps or boilers, which could potentially also participate in a capacity mechanism, in some cases as flexible producers or consumers. For this reason, therefore, interrelationships between a possible capacity mechanism and the development of the grid-connected heat supply will have to be carefully discussed.

- In addition, future funding mechanisms will have to ensure that the revenues from the electricity market – specifically the new market segment for capacity payments – are taken into account when determining the level of funding. The avoidance of double funding is ultimately also an objective prescribed by European law. The interrelationships between a possible capacity mechanism and the heat supply will have to be analysed in depth and taken into account in the future regulatory framework for the electricity and heat supply.

5 Consultation

With this paper, the BMWK has presented options for the future electricity market design, for an investment framework for renewable energy sources, an investment framework for controllable capacities, locational signals and flexibility, all of which essentially expand on the discussions that have taken place within the Platform Climate-Neutral Electricity System.

To ensure that the political decisions on the future electricity market design are well prepared, the BMWK is interested in receiving feedback on this electricity market paper. The BMWK invites the general public, therefore, to take part in a written consultation on this electricity market paper. To this end, the BMWK has prepared a number of key questions relating to the individual fields of action, on which the BMWK would welcome feedback.

It is possible to take part in the consultation with immediate effect until 6 September 2024. Contributions can be submitted using the following online form: https://survey.lamapoll.de/Umfrage-zum-Strommarktpapier.

We will publish the opinions and comments submitted on the BMWK website. For this reason, please limit the information you provide in order to protect your personal data. You may object to the publication of the opinions and comments you provide by sending a notification to this effect to pkns@dena.de.

The BMWK will analyse the feedback and then publish the results.

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